UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 40-F

☐ **REGISTRATION STATEMENT PURSUANT TO SECTION 12 OF THE SECURITIES EXCHANGE ACT OF 1934**

OR

☒ **ANNUAL REPORT PURSUANT TO SECTION 13(a) OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended December 31, 2019 **Commission File Number 001-37946**

ALGONQUIN POWER & UTILITIES CORP.

(Exact name of Registrant as specified in its charter)

N/A
(Translation of Registrant's name into English (if applicable))

Canada
(Province or other jurisdiction of incorporation or organization)

4911
(Primary Standard Industrial Classification Code Number (if applicable))

N/A
(I.R.S. Employer Identification Number (if applicable))

---

354 Davis Road
Oakville, Ontario
L6J 2X1, Canada
(905) 465-4500
(Address and telephone number of Registrant's principal executive offices)

CT Corporation System
111 Eighth Avenue
New York, New York 10011
(212) 894-8940
(Name, address (including zip code) and telephone number (including area code) of agent for service in the United States)

Securities registered or to be registered pursuant to Section 12(b) of the Act:

Title of each class	Trading Symbol(s)	Name of each exchange on which registered
Common shares, no par value	AQN	The New York Stock Exchange
6.875% Fixed-to-Floating Subordinated Notes – Series 2018-A due October 17, 2078	AQNA	The New York Stock Exchange
6.20% Fixed-to-Floating Subordinated Notes – Series 2019-A due July 1, 2079	AQNB	The New York Stock Exchange
Rights to Purchase One Common Share of the Company	N/A	The New York Stock Exchange

Securities registered or to be registered pursuant to Section 12(g) of the Act:

Common Shares, no par value

(Title of Class)

Securities for which there is a reporting obligation pursuant to Section 15(d) of the Act: None

For annual reports, indicate by check mark the information filed with this Form:

☒ **Annual Information Form** ☒ **Audited Annual Financial Statements**

Indicate the number of outstanding shares of each of the issuer's classes of capital or common stock as of the close of the period covered by the annual report:

As of December 31, 2019, there were 524,223,323 Common Shares outstanding.

Indicate by check mark whether the Registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Exchange Act during the preceding 12 months (or for such shorter period that the Registrant was required to file such reports) and (2) has been subject to such filing requirements for the past 90 days.

Yes ☒ No ☐

Indicate by check mark whether the Registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the Registrant was required to submit such files).

Yes ☒ **No** ☐

Indicate by check mark whether the registrant is an emerging growth company as defined in Rule 12b-2 of the Exchange Act.
Emerging growth company ☐

If an emerging growth company that prepares its financial statements in accordance with U.S. GAAP, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

This Annual Report on Form 40-F shall be incorporated by reference into or as an exhibit to, as applicable, the registrant's Registration Statements on Form F-3 (File Nos. 333-220059 and 333-227246), F-10 (File No. 333-216616 and 333-227245) and Form S-8 (File Nos. 333-177418, 333-213648, 333-218810, 333-213650 and 333-232012) under the Securities Act of 1933, as amended.

ANNUAL INFORMATION FORM

The Annual Information Form (the “AIF”) of Algonquin Power & Utilities Corp. (“APUC” or the “Company”) for the fiscal year ended December 31, 2019 is filed as Exhibit 99.1 to this annual report on Form 40-F. All capitalized terms used herein but not otherwise defined herein shall have the meanings given to such terms in the AIF.

AUDITED ANNUAL FINANCIAL STATEMENTS

The Audited Annual Financial Statements of APUC for the fiscal year ended December 31, 2019 (the “Financial Statements”) are filed as Exhibit 99.2 to this annual report on Form 40-F.

MANAGEMENT’S DISCUSSION AND ANALYSIS

The Management’s Discussion and Analysis for the fiscal year ended December 31, 2019 (the “MD&A”) is filed as Exhibit 99.3 to this annual report on Form 40-F.

DISCLOSURE CONTROLS AND PROCEDURES

The information provided under the heading “Disclosure Controls and Procedures” in the MD&A, filed as Exhibit 99.3 to this annual report on Form 40-F, is incorporated by reference herein.

INTERNAL CONTROL OVER FINANCIAL REPORTING

A. Management’s report on internal control over financial reporting

The Company’s management, including its chief executive officer and chief financial officer, is responsible for establishing and maintaining adequate internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with U.S. generally accepted accounting principles (“U.S. GAAP”).

The Company’s internal control over financial reporting framework includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the Company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with U.S. GAAP, and that receipts and expenditures of the Company are being made only in accordance with authorizations of management and directors of the Company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of the Company’s assets that could have a material effect on the Company’s consolidated financial statements.

Due to its inherent limitations, internal control over financial reporting may not prevent or detect all misstatements. Further, the effectiveness of internal control is subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with policies or procedures may change.

During the year ended December 31, 2019, the Company acquired Enbridge Gas New Brunswick Limited Partnership ("New Brunswick Gas") and St. Lawrence Gas Company, Inc. ("St. Lawrence Gas"). Management is in the process of evaluating the existing controls and procedures of New Brunswick Gas and St. Lawrence Gas and integrating financial reporting and controls for New Brunswick Gas and St. Lawrence gas into the Company's internal control over financial reporting. The financial information for these acquisitions is included in the MD&A and in note 3 to the Financial Statements. As permitted under applicable laws, due to the complexity associated with assessing internal controls during integration efforts, the Company excluded these acquisitions from its evaluation of the effectiveness of the Company's internal controls over financial reporting as of December 31, 2019 (representing approximately 4% of our total assets as of December 31, 2019 and approximately 2% of our revenues for the year ended December 31, 2019).

Management assessed the effectiveness of APUC’s internal control over financial reporting as of December 31, 2019, based on the framework established in Internal Control – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). This assessment evaluation included review of the documentation of controls, evaluation of the design effectiveness of controls, testing of the operating effectiveness of controls and a conclusion on this evaluation. Based on this assessment, management concluded that APUC’s internal control over financial reporting was effective as of December 31, 2019 to provide reasonable assurance regarding the reliability of financial reporting and the preparation of consolidated financial statements for external reporting purposes in accordance with U.S. GAAP. Management reviewed the results of its assessment with the Audit Committee of the Board of Directors of the Company.

B. Auditor’s attestation report on internal control over financial reporting

Ernst & Young LLP, the independent registered public accounting firm of APUC, which audited the consolidated financial statements of APUC for the year ended December 31, 2019, has also issued an attestation report on the effectiveness of APUC’s internal control over financial reporting as of December 31, 2019. The attestation report is provided in Exhibit 99.2 to this annual report on Form 40-F and is incorporated by reference herein.

C. Changes in internal control over financial reporting

The information provided under the heading “Changes in Internal Controls Over Financial Reporting” in the MD&A, filed as Exhibit 99.3 to this annual report on Form 40-F, is incorporated by reference herein.

AUDIT COMMITTEE FINANCIAL EXPERTS

APUC’s board of directors has determined that it has two audit committee financial experts serving on its audit committee. Christopher Ball and Dilek Samil have been determined to be such audit committee financial experts and are “independent” as set forth in the Canadian National Instrument 58-101 *Disclosure of Corporate Governance Practices* and Rule 10A-3 of the Exchange Act. The SEC has indicated that the designation as an audit committee financial expert does not make a person an “expert” for any purpose, impose any duties, obligations or liability on such persons that are greater than those imposed on members of the audit committee and board of directors who do not carry this designation or affect the duties, obligations or liability of any other member of the audit committee or board of directors.

CODE OF ETHICS

APUC has adopted a code of business conduct and ethics (the “Code of Conduct”) that applies to all employees and officers, including its Chief Executive Officer and Chief Financial Officer. The Code of Conduct is available without charge to any shareholder upon request to Amelia Tsang, Telephone: (905) 465-4500, E-mail: InvestorRelations@APUCorp.com, Algonquin Power & Utilities Corp., 354 Davis Road, Oakville, Ontario L6J 2X1.

PRINCIPAL ACCOUNTANT FEES AND SERVICES

The information provided under the heading “Pre-Approval Policies and Procedures” in the AIF, filed as Exhibit 99.1 to this annual report on Form 40-F, is incorporated by reference herein. All audit services, audit-related services, tax services, and other services provided for the years ended December 31, 2018 and 2019 were pre-approved by the audit committee.

OFF-BALANCE SHEET ARRANGEMENTS

APUC’s off-balance sheet arrangements consist of obligations under equity capital contribution agreements and guarantees for certain development projects which the Company does not have sole control. These instruments provide financial assurance necessary for the continued development and construction of the projects. APUC also pledged its shares in Atlantica Yield plc (“Atlantica”) as collateral to a secured credit facility issued by the Company’s equity-method investee. For a discussion of these arrangements, refer to the information in note 8 to the Financial Statements, filed as Exhibit 99.2 to this annual report on Form 40-F and is incorporated by reference herein, and the information under the heading “Enterprise Risk Management – Operational Risk Management – Joint Venture Investment Risk” in the MD&A, filed as Exhibit 99.3 to this annual report on Form 40-F and is incorporated by reference herein.

TABULAR DISCLOSURE OF CONTRACTUAL OBLIGATIONS

The information provided under the heading "Contractual Obligations" in the MD&A, filed as Exhibit 99.3 to this annual report on Form 40-F, is incorporated by reference herein.

NON-GAAP FINANCIAL MEASURES

The AIF and MD&A contain financial measures that are not recognized measures under U.S. GAAP. Such terms include: "Adjusted Net Earnings", "Adjusted Earnings Before Interest, Taxes, Depreciation and Amortization" ("Adjusted EBITDA"), "Adjusted Funds from Operations", "Net Energy Sales", "Net Utility Sales" and "Divisional Operating Profit". There is no standardized measure of these terms and, consequently, the Company's method of calculating these measures may differ from methods used by other companies and may not be comparable to similar measures presented by other companies. A calculation and analysis of "Adjusted Net Earnings", "Adjusted EBITDA", "Adjusted Funds from Operations", "Net Energy Sales", "Net Utility Sales", and "Divisional Operating Profit" can be found in the MD&A, which is attached hereto as Exhibit 99.3 and incorporated herein by reference.

CAUTION CONCERNING FORWARD LOOKING STATEMENTS

This document may contain statements that constitute "forward-looking information" within the meaning of applicable securities laws in each of the provinces of Canada and the respective policies, regulations and rules under such laws or "forward-looking statements" within the meaning of the U.S. Private Securities Litigation Reform Act of 1995 (collectively, "forward-looking information"). The words "anticipates", "believes", "budget", "could", "estimates", "expects", "forecasts", "intends", "may", "might", "plans", "projects", "schedule", "should", "will", "would" and similar expressions are often intended to identify forward-looking information, although not all forward-looking information contains these identifying words. Specific forward-looking information in this document or incorporated by reference herein from the AIF or MD&A includes, but is not limited to, statements relating to:

- the future growth, results of operations, performance, business prospects and opportunities of the Company;
- expectations regarding earnings and cash flow;
- statements relating to renewable energy credits expected to be generated and sold;
- tax credits expected to be available and/or received;
- the expected timeline for regulatory approvals and permits;
- the expected approval timing and cost of various transactions;
- expectations and plans with respect to current and planned capital projects;
- expectations with respect to revenues pursuant to energy production hedges;
- ongoing and planned acquisitions, projects and initiatives, including expectations regarding costs, financing, results and expected completion dates;
- expectations regarding the Company's corporate development activities and the results thereof including the expected business mix between the Regulated Services Group and Renewable Energy Group;
- the resolution of legal and regulatory proceedings;
- expected demand for renewable sources of power; government procurement opportunities;
- expected capacity of and energy sales from new energy projects;
- business plans for the Company's subsidiaries and joint ventures;
- expected future base rates;
- environmental liabilities;
- dividends to shareholders;
- the timing for closing of pending acquisitions, including the acquisitions of New York American Water and Ascendant;
- liquidity, capital resources and operational requirements;
- rate reviews, including resulting decisions and rates and expected impacts and timing;

- sources of funding, including adequacy and availability of credit facilities, debt maturation and future borrowings;
- expectations regarding the use of proceeds from equity financing;
- ongoing and planned acquisitions, projects and initiatives, including expectations regarding costs, financing, results and completion dates;
- expectations regarding the Company's corporate development activities and the results thereof;
- expectations regarding regulatory hearings, motions and approvals;
- expectations regarding the cost of operations, capital spending and maintenance, and the variability of those costs;
- expected future capital investments, including expected timing, investment plans, sources of funds and impacts;
- expectations regarding generation availability, capacity and production;
- expectations regarding the outcome of existing or potential legal and contractual claims and disputes;
- expectations regarding the ability to access the capital market on reasonable terms;
- strategy and goals;
- expectations regarding succession planning;
- contractual obligations and other commercial commitments;
- expectations regarding the maturity and redemption of our outstanding subordinated notes;
- expectations regarding the impact of tax reforms;
- credit ratings;
- anticipated growth and emerging opportunities in our target markets;
- accounting estimates;
- interest rates;
- currency exchange rates; and
- commodity prices.

All forward-looking information is given pursuant to the “safe harbor” provisions of applicable securities legislation.

The forecasts and projections that make up the forward-looking information contained herein are based on certain factors or assumptions which include, but are not limited to: the receipt of applicable regulatory approvals and requested rate decisions; the absence of material adverse regulatory decisions being received and the expectation of regulatory stability; the absence of any material equipment breakdown or failure; availability of financing on commercially reasonable terms and the stability of credit ratings of the Company and its subsidiaries; the absence of unexpected material liabilities or uninsured losses; the continued availability of commodity supplies and stability of commodity prices; the absence of sustained interest rate increases or significant currency exchange rate fluctuations; the absence of significant operational or supply chain disruptions or liability due to natural disasters, diseases or catastrophic events; the continued ability to maintain systems and facilities to ensure their continued performance; the absence of a severe and prolonged downturn in general economic, credit, social and market conditions; the successful and timely development and construction of new projects; the absence of material capital project or financing cost overruns; sufficient liquidity and capital resources; the continuation of observed weather patterns and trends; the absence of significant counterparty defaults; the continued competitiveness of electricity pricing when compared with alternative sources of energy; the realization of the anticipated benefits of the Company’s acquisitions and joint ventures; the absence of a material change in political conditions or public policies and directions by governments materially negatively affecting the Company; the ability to obtain and maintain licenses and permits; the absence of a material decrease in market energy prices; the absence of material disputes with taxation authorities or changes to applicable tax laws; continued maintenance of information technology infrastructure and the absence of a material breach of cyber security; favorable relations with external stakeholders; and favorable labor relations.

The forward-looking information contained herein is subject to risks, uncertainties and other factors that could cause actual results to differ materially from historical results or results anticipated by the forward-looking information.

Factors which could cause results or events to differ materially from current expectations include, but are not limited to: changes in general economic, credit, social and market conditions; changes in customer energy usage patterns and energy demand; global climate change; the incurrence of environmental liabilities; natural disasters and other catastrophic events; the failure of information technology infrastructure and cybersecurity; the loss of key personnel and/or labor disruptions; seasonal fluctuations and variability in weather conditions and natural resource availability; reductions in demand for electricity, gas and water due to developments in technology; reliance on transmission systems owned and operated by third parties; issues arising with respect to land use rights and access to the Company's facilities; critical equipment breakdown or failure; terrorist attacks; fluctuations in commodity prices; capital expenditures; reliance on subsidiaries; the incurrence of an uninsured loss; a credit rating downgrade; an increase in financing costs or limits on access to credit and capital markets; sustained increases in interest rates; currency exchange rate fluctuations; restricted financial flexibility due to covenants in existing credit agreements; an inability to refinance maturing debt on commercially reasonable terms; disputes with taxation authorities or changes to applicable tax laws; failure to identify, acquire, develop or timely place in service projects to maximize the value of production tax credit qualified equipment; requirement for greater than expected contributions to post-employment benefit plans; default by a counterparty; inaccurate assumptions, judgments and/or estimates with respect to asset retirement obligations; failure to maintain required regulatory authorizations; changes to health and safety laws, regulations or permit requirements; failure to comply with and/or changes to environmental laws, regulations and other standards; compliance with new foreign laws or regulations; failure to identify attractive acquisition or development candidates necessary to pursue the Company's growth strategy; delays and cost overruns in the design and construction of projects, including as a result of the 2019 novel coronavirus outbreak in China; loss of key customers; failure to realize the anticipated benefits of acquisitions or joint ventures; Atlantica or the Company's joint venture with Abengoa S.A. acting in a manner contrary to the Company's interests; a drop in the market value of Atlantica's ordinary shares; facilities being condemned or otherwise taken by governmental entities; increased external stakeholder activism adverse to the Company's interests; and fluctuations in the price and liquidity of the Company's common shares. Although the Company has attempted to identify important factors that could cause actual actions, events or results to differ materially from those described in forward-looking information, there may be other factors that cause actions, events or results not to be as anticipated, estimated or intended. Some of these and other factors are discussed in more detail under the heading "Enterprise Risk Factors" in our AIF, filed as Exhibit 99.1 to this annual report on Form 40-F.

Forward-looking information contained herein is made as of the date of this document and based on the plans, beliefs, estimates, projections, expectations, opinions and assumptions of management on the date hereof. There can be no assurance that forward-looking information will prove to be accurate, as actual results and future events could differ materially from those anticipated in such forward-looking information. Accordingly, readers should not place undue reliance on forward-looking information. While subsequent events and developments may cause the Company's views to change, the Company disclaims any obligation to update any forward-looking information or to explain any material difference between subsequent actual events and such forward-looking information, except to the extent required by applicable law. All forward-looking information contained herein is qualified by these cautionary statements.

IDENTIFICATION OF THE AUDIT COMMITTEE

APUC has a standing Audit Committee of its board of directors established in accordance with Section 3(a)(58)(A) of the Exchange Act. The information provided under the heading "Audit Committee" identifying APUC's Audit Committee and confirming the independence of the Audit Committee in the AIF, filed as Exhibit 99.1 to this annual report on Form 40-F, is incorporated by reference herein.

INTERACTIVE DATA FILE

The required disclosure for the fiscal year ended December 31, 2019 is filed as Exhibit 101 to this annual report on Form 40-F.

MINE SAFETY DISCLOSURE

Not applicable.

COMPARISON OF NYSE CORPORATE GOVERNANCE RULES

APUC is subject to corporate governance requirements prescribed under applicable Canadian corporate governance practices, including the rules of the Toronto Stock Exchange ("Canadian Rules"). APUC is also subject to corporate governance requirements prescribed by the listing standards of the New York Stock Exchange ("NYSE") Stock Market, and certain rules and regulations promulgated by the SEC under the Exchange Act (including those applicable rules and regulations mandated by the Sarbanes-Oxley Act of 2002). In particular, Section 303A.00 of the NYSE Listed Company Manual requires APUC to have an audit committee that meets the requirements of Rule 10A-3 of the Exchange Act, and Section 303A.011 of the NYSE Listed Company Manual requires APUC to disclose any significant ways in which its corporate governance practices differ from those followed by U.S. companies listed on the NYSE. A description of those differences follows.

Section 303A.01 of the NYSE Listed Company Manual requires that boards have a majority of independent directors and Section 303A.02 defines independence standards for directors. APUC's Board of Directors is responsible for determining whether or not each director is independent. In making this determination, the Board of Directors has adopted the definition of "independence" as set forth in the Canadian National Instrument 58-101 *Disclosure of Corporate Governance Practices*. In applying this definition, the Board of Directors considers all relationships of its directors, including business, family and other relationships. APUC's Board of Directors also determines whether each member of its Audit Committee is independent pursuant to Canadian National Instrument 52-110 *Audit Committees* and Rule 10A-3 of the Exchange Act.

Section 303A.04(a) of the NYSE Listed Company Manual requires that all members of the nominating/corporate governance committee be independent. APUC's Corporate Governance Committee includes one director who is not independent, but the Committee has appointed a Nominating Sub-Committee consisting solely of independent directors that performs all responsibilities relating to the director nominations process.

Section 303A.05(a) of the NYSE Listed Company Manual requires that all members of the compensation committee be independent.

Section 303A.07(b)(iii)(A) of the NYSE Listed Company Manual requires, among other things, that the written charter of the audit committee state that the audit committee at least annually, obtain and review a report by the independent auditor describing the firm's internal quality-control procedures, any material issues raised by the most recent internal quality-control review, or peer review, of the firm, or by any inquiry or investigation by governmental or professional authorities, within the preceding five years, respecting one or more independent audits carried out by the firm, and any steps taken to deal with any such issues. The written charter of the audit committee complies with Canadian Rules, but does not explicitly state that these functions are part of the purpose of the audit committee, which is not required by Canadian Rules.

Section 303A.08 of the NYSE Listed Company Manual requires that shareholders of a listed company be given the opportunity to vote on all equity compensation plans and material revisions thereto. APUC complies with Canadian Rules, which generally require that shareholders approve equity compensation plans. However, the Canadian Rules are not identical to the NYSE Rules. For example, Canadian Rules require shareholder approval of equity compensation plans only when such plans involve the issuance or potential issuance of newly issued securities. In addition, equity compensation plans that do not provide for a fixed maximum number of securities to be issued must have a rolling maximum number of securities to be issued, based on a fixed percentage of the issuer's outstanding securities and must also be approved by shareholders every three years. If a plan provides a procedure for its amendment, Canadian Rules require shareholder approval of amendments only where the amendment involves a reduction in the exercise price or purchase price, or an extension of the term of an award benefiting an insider, the removal or exceeding of the insider participation limit prescribed by the Canadian Rules, an increase to the maximum number of securities issuable, or is an amendment to the amending provision itself.

Section 303A.09 of the NYSE Listed Company Manual requires that listed companies adopt and disclose corporate governance guidelines that address certain topics, including director compensation guidelines. APUC has adopted its Board Mandate, which is the equivalent of corporate governance guidelines, in compliance with the Canadian Rules.

APUC's corporate governance guidelines do not address director compensation, but APUC provides disclosure about the decision making process for non-employee director compensation in the annual management information circular and APUC has adopted a policy on share ownership guidelines for non-employee directors.

Section 303A.10 of the NYSE Listed Company Manual requires that a listed company's code of business conduct and ethics mandate that any waiver of the code for executive officers or directors may be made only by the board or a board committee and must be promptly disclosed to shareholders. APUC's code of business conduct and ethics complies with Canadian Rules and does not include such a requirement.

Section 312 of the NYSE Listed Company Manual requires that a listed company obtain shareholder approval prior to the issuance of securities in connection with the establishment or amendment of certain equity compensation plans, issuances of securities to related parties, the issuance of 20% or greater of shares outstanding or voting power and issuances that will result in a change in control. APUC will follow the Canadian Rules for shareholder approval of new issuances of its common shares. Following the Canadian Rules, shareholder approval is required for certain issuances of shares that (i) materially affect control of APUC or (ii) provide consideration to insiders in aggregate of 10% or greater of the market capitalization of the listed issuer and have not been negotiated at arm's length. Shareholder approval is also required, pursuant to the Canadian Rules, in the case of private placements (x) for an aggregate number of listed securities issuable greater than 25% of the number of securities of the listed issuer which are outstanding, on a non-diluted basis, prior to the date of closing of the transaction if the price per security is less than the market price or (y) that during any six month period are to insiders for listed securities or options, rights or other entitlements to listed securities greater than 10% of the number of securities of the listed issuer which are outstanding, on a non-diluted basis, prior to the date of the closing of the first private placement to an insider during the six month period.

In addition to the foregoing, the Company may from time-to-time seek relief from the NYSE corporate governance requirements on specific transactions under the NYSE Listed Company Guide, in which case, the Company expects to make the disclosure of such transactions available on the Company's website at www.algonquinpowerandutilities.com. Information contained on the Company's website is not part of this annual report on Form 40-F.

UNDERTAKING

APUC undertakes to make available, in person or by telephone, representatives to respond to inquiries made by the Commission staff, and to furnish promptly, when requested to do so by the Commission staff, information relating to the securities in relation to which the obligation to file an annual report on Form 40-F arises or transactions in said securities.

CONSENT TO SERVICE OF PROCESS

APUC previously filed with the Commission a written irrevocable consent and power of attorney on Form F-X.
Any change to the name or address of the agent for service of APUC shall be communicated promptly to the Commission by amendment to Form F-X referencing the file number of APUC.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, as amended, the Registrant certifies that it meets all of the requirements for filing on Form 40-F and has duly caused this annual report to be signed on its behalf by the undersigned, thereto duly authorized.

ALGONQUIN POWER & UTILITIES CORP.
(Registrant)

Date: February 27, 2020	By:	/s/ David Bronicheski
	Name:	David Bronicheski
	Title:	Chief Financial Officer

EXHIBIT INDEX

99.1	Annual Information Form of APUC for the year ended December 31, 2019.
99.2	Audited Annual Financial Statements of APUC for the year ended December 31, 2019.
99.3	Management's Discussion & Analysis of APUC for the year ended December 31, 2019.
99.4	Consent Letter from Ernst & Young LLP.
99.5	Certifications of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
99.6	Certifications of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
99.7	Certifications of Chief Executive Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
99.8	Certifications of Chief Financial Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
101	Inline Interactive Data File.
104	Cover Page Interactive Data File.

ALGONQUIN POWER & UTILITIES CORP.

ANNUAL INFORMATION FORM
For the year ended December 31, 2019

February 27, 2020

All information contained in this AIF is presented as at December 31, 2019, unless otherwise specified. In this AIF, all dollar figures are in U.S. dollars, unless otherwise indicated.

TABLE OF CONTENTS

TABLE OF CONTENTS
(continued)

Caution Concerning Forward-looking Statements and Forward-looking Information

This document may contain statements that constitute “forward-looking information” within the meaning of applicable securities laws in each of the provinces of Canada and the respective policies, regulations and rules under such laws or “forward-looking statements” within the meaning of the U.S. Private Securities Litigation Reform Act of 1995 (collectively, “forward-looking information”). The words “anticipates”, “believes”, “budget”, “could”, “estimates”, “expects”, “forecasts”, “intends”, “may”, “might”, “plans”, “projects”, “schedule”, “should”, “will”, “would” and similar expressions are often intended to identify forward-looking information, although not all forward-looking information contains these identifying words. Specific forward-looking information in this document includes, but is not limited to, statements relating to: the future growth, results of operations, performance, business prospects and opportunities of the Corporation; expectations regarding earnings and cash flow; expectations regarding credit ratings and the maintenance thereof, statements relating to renewable energy credits expected to be generated and sold; tax credits expected to be available and/or received; the expected timeline for regulatory approvals and permits; the expected approval timing and cost of various transactions; expectations and plans with respect to current and planned capital projects; expectations with respect to revenues pursuant to energy production hedges; ongoing and planned acquisitions, projects and initiatives, including expectations regarding costs, financing, results and expected completion dates; expectations regarding the Corporation’s corporate development activities and the results thereof; the resolution of legal and regulatory proceedings; expected demand for renewable sources of power; government procurement opportunities; expected capacity of and energy sales from new energy projects; business plans for APUC’s subsidiaries and joint ventures; expected future base rates; environmental liabilities; dividends to shareholders; and the timing for closing of pending acquisitions, including the acquisitions of Ascendant and New York American Water. All forward-looking information is given pursuant to the “safe harbour” provisions of applicable securities legislation.

The forecasts and projections that make up the forward-looking information contained herein are based on certain factors or assumptions which include, but are not limited to: the receipt of applicable regulatory approvals and requested rate decisions; the absence of material adverse regulatory decisions being received and the expectation of regulatory stability; the absence of any material equipment breakdown or failure; availability of financing on commercially reasonable terms and the stability of credit ratings of the Corporation and its subsidiaries; the absence of unexpected material liabilities or uninsured losses; the continued availability of commodity supplies and stability of commodity prices; the absence of sustained interest rate increases or significant currency exchange rate fluctuations; the absence of significant operational or supply chain disruptions or liability due to natural disasters, diseases or catastrophic events; the continued ability to maintain systems and facilities to ensure their continued performance; the absence of a severe and prolonged downturn in general economic, credit, social and market conditions; the successful and timely development and construction of new projects; the absence of material capital project or financing cost overruns; sufficient liquidity and capital resources; the continuation of observed weather patterns and trends; the absence of significant counterparty defaults; the continued competitiveness of electricity pricing when compared with alternative sources of energy; the realization of the anticipated benefits of the Corporation’s acquisitions and joint ventures; the absence of a material change in political conditions or public policies and directions by governments materially negatively affecting the Corporation; the ability to obtain and maintain licenses and permits; the absence of a material decrease in market energy prices; the absence of material disputes with taxation authorities or changes to applicable tax laws; continued maintenance of information technology infrastructure and the absence of a material breach of cyber security; favourable relations with external stakeholders; and favourable labour relations.

The forward-looking information contained herein is subject to risks, uncertainties and other factors that could cause actual results to differ materially from historical results or results anticipated by the forward-looking information. Factors which could cause results or events to differ materially from current expectations include, but are not limited to: changes in general economic, credit, social and market conditions; changes in customer energy usage patterns and energy demand; global climate change; the incurrence of environmental liabilities; natural disasters and other catastrophic events; the failure of information technology infrastructure and cybersecurity; the loss of key personnel and/or labour disruptions; seasonal fluctuations and variability in weather conditions and natural resource availability; reductions in demand for electricity, gas and water due to developments in technology; reliance on transmission systems owned and operated by third parties; issues arising with respect to land use rights and access to the Corporation’s facilities; critical equipment breakdown or failure; terrorist attacks; fluctuations in commodity prices; capital expenditures; reliance on subsidiaries; the incurrence of an uninsured loss; a credit rating downgrade; an increase in financing costs or limits on access to credit and capital markets; sustained increases in interest rates; currency exchange rate fluctuations; restricted financial flexibility due to covenants in existing credit agreements; an inability to refinance maturing debt on commercially reasonable terms; disputes with taxation authorities or changes to applicable tax laws; failure to identify, acquire, develop or timely place in service projects to maximize the value of PTC qualified equipment; requirement for greater than expected contributions to post-employment benefit plans; default by a counterparty; inaccurate assumptions, judgments and/or estimates with respect to asset retirement obligations; failure to maintain required regulatory authorizations; changes to health and safety laws, regulations or permit requirements; failure to comply with and/or changes to environmental laws, regulations and other standards; compliance with new foreign laws or regulations; failure to identify attractive acquisition or development candidates necessary to pursue the Corporation's growth strategy; delays and cost overruns in the design and construction of projects, including as a result of the 2019 novel coronavirus outbreak in China (the "**2019 Novel Coronavirus**"); loss of key customers; failure to realize the anticipated benefits of acquisitions or joint ventures; Atlantica or the Corporation's joint venture with Abengoa acting in a manner contrary to the Corporation's interests; a drop in the market value of Atlantica's ordinary shares; facilities being condemned or otherwise taken by governmental entities; increased external stakeholder activism adverse to the Corporation's interests; and fluctuations in the price and liquidity of the Common Shares. Although the Corporation has attempted to identify important factors that could cause actual actions, events or results to differ materially from those described in forward-looking information, there may be other factors that cause actions, events or results not to be as anticipated, estimated or intended. Some of these and other factors are discussed in more detail under the heading "Enterprise Risk Factors".

Forward-looking information contained herein is made as of the date of this document and based on the plans, beliefs, estimates, projections, expectations, opinions and assumptions of management on the date hereof. There can be no assurance that forward-looking information will prove to be accurate, as actual results and future events could differ materially from those anticipated in such forward-looking information. Accordingly, readers should not place undue reliance on forward-looking information. While subsequent events and developments may cause the Corporation's views to change, the Corporation disclaims any obligation to update any forward-looking information or to explain any material difference between subsequent actual events and such forward-looking information, except to the extent required by applicable law. All forward-looking information contained herein is qualified by these cautionary statements.

Non-GAAP Financial Measures

The terms "Net Utility Sales" and "Net Energy Sales" are used in this AIF. These terms are not recognized measures under U.S. GAAP. There is no standardized measure of "Net Utility Sales" or "Net Energy Sales"; consequently, APUC's method of calculating these measures may differ from methods used by other companies and therefore may not be comparable to similar measures presented by other companies. A calculation and analysis of "Net Utility Sales" and "Net Energy Sales" can be found in APUC's Management's Discussion and Analysis ("**MD&A**") for the year ended December 31, 2019 (which may be found on SEDAR at www.sedar.com and on EDGAR at www.sec.gov/edgar) under the headings "Regulated Services Group – 2019 Regulated Services Group Operating Results" and "Renewable Energy Group – 2019 Renewable Energy Group Operating Results". Such calculations and analysis are incorporated by reference herein.

<u>Net Utility Sales</u>

Net Utility Sales is a non-GAAP measure used by investors to identify utility revenue after commodity costs, either natural gas or electricity, where these commodity costs are generally included as a pass through in rates to its utility customers. APUC uses Net Utility Sales to assess its utility revenues without the effects of fluctuating commodity costs as such costs are predominantly passed through and paid for by utility customers. APUC believes that analysis and presentation of Net Utility Sales on this basis will enhance an investor's understanding of the revenue generation of its utility businesses. It is not intended to be representative of revenue as determined in accordance with U.S. GAAP.

<u>Net Energy Sales</u>

Net Energy Sales is a non-GAAP measure used by investors to identify revenue after commodity costs used to generate revenue where such revenue generally increases or decreases in response to increases or decreases in the cost of the commodity used to produce that revenue. APUC uses Net Energy Sales to assess its revenues without the effects of fluctuating commodity costs as such costs are predominantly passed through either directly or indirectly in the rates that are charged to customers. APUC believes that analysis and presentation of Net Energy Sales on this basis will enhance an investor's understanding of the revenue generation of its businesses. It is not intended to be representative of revenue as determined in accordance with U.S. GAAP.

1. CORPORATE STRUCTURE

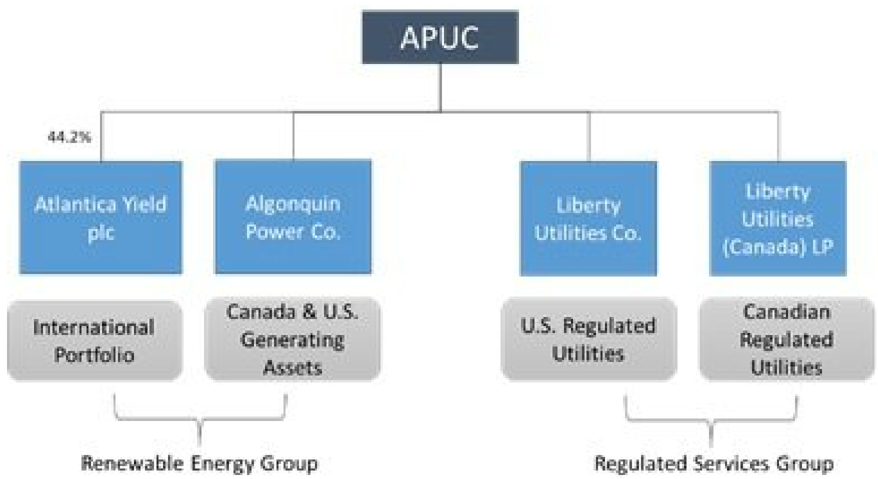
1.1 Name, Address and Incorporation

Algonquin Power & Utilities Corp. ("**APUC**") was originally incorporated under the *Canada Business Corporations Act* on August 1, 1988 as Traduction Militech Translation Inc. Pursuant to articles of amendment dated August 20, 1990 and January 24, 2007, the Corporation amended its articles to change its name to Société Hydrogenique Incorporée – Hydrogenics Corporation and Hydrogenics Corporation – Corporation Hydrogenique, respectively. Pursuant to a certificate and articles of arrangement dated October 27, 2009, the Corporation, among other things, created a new class of common shares, transferred its existing operations to a newly formed independent corporation, exchanged new common shares for all of the trust units of Algonquin Power Co. ("**APCo**") and changed its name to Algonquin Power & Utilities Corp. The head and registered office of APUC is located at Suite 100, 354 Davis Road, Oakville, Ontario L6J 2X1.

Unless the context indicates otherwise, references in this AIF to the "**Corporation**" refer collectively to APUC, its direct or indirect subsidiary entities and partnership interests held by APUC and its subsidiary entities.

1.2 Intercorporate Relationships

Most of the Corporation's business is conducted through subsidiary entities, including those entities which hold project assets. The following represents a summarized organizational chart for the Corporation.



The following table outlines the Corporation's significant subsidiaries, and excludes certain other subsidiaries. The assets and revenues of the excluded subsidiaries did not individually exceed 10%, or in the aggregate exceed 20%, of the total consolidated assets or total consolidated revenues of the Corporation as at December 31, 2019. The voting securities of each subsidiary are held in the form of common shares, share quotas or partnership interests in the case of partnerships and their foreign equivalents, and units in the case of trusts.

Significant Subsidiaries	Description	Jurisdiction	Ownership of Voting Securities
RENEWABLE ENERGY GROUP			
AAGES (AY Holdings) B.V. ("**AY Holdings**")	Owner of equity interest in Atlantica	Netherlands	100%
Algonquin Power Co. (or APCo dba Liberty Power)		Ontario	100%
St. Leon Wind Energy LP ("**St. Leon LP**")	Owner of the St. Leon Wind Facility	Manitoba	100%
Minonk Wind, LLC	Owner of the Minonk Wind Facility	Delaware	100%[1]
Senate Wind, LLC	Owner of the Senate Wind Facility	Delaware	100%[1]
GSG 6, LLC	Owner of the Shady Oaks Wind Facility	Illinois	100%
Odell Wind Farm, LLC	Owner of the Odell Wind Facility	Minnesota	100%[1]
Deerfield Wind Energy, LLC	Owner of the Deerfield Wind Facility	Delaware	100%[1]
Great Bay Solar I, LLC	Owner of the Great Bay Solar Facility	Maryland	100%[1]
REGULATED SERVICES GROUP			
Liberty Utilities (Canada) Corp.		Canada	100%
Liberty Utilities Co.		Delaware	100%
Liberty Utilities (CalPeco Electric) LLC	Owner of the CalPeco Electric System	California	100%
Liberty Utilities (Granite State Electric) Corp.	Owner of the Granite State Electric System	New Hampshire	100%
Liberty Utilities (EnergyNorth Natural Gas) Corp.	Owner of the EnergyNorth Gas System	New Hampshire	100%
Liberty Utilities (Midstates Natural Gas) Corp.	Owner of the Midstates Gas Systems	Missouri	100%
Liberty Utilities (Peach State Natural Gas) Corp.	Owner of the Peach State Gas System	Georgia	100%
Liberty Utilities (New England Natural Gas Company) Corp.	Owner of the New England Gas System	Delaware	100%
The Empire District Electric Company ("**Empire**")	Owner of, among other things, (i) electric and water distribution and electric transmission utility assets serving locations in Missouri, Kansas, Oklahoma and Arkansas, (ii) the Mid-West wind development project, and (iii) the Ozark Beach hydro facility in Missouri, the Riverton, Energy Center, and Stateline No. 1 natural gas-fired power generation facilities in Kansas and Missouri, the Asbury coal-fired power generation facility in Missouri and a 60% interest in the Stateline combined cycle gas facility in Missouri	Kansas	100%
The Empire District Gas Company ("**EDG**")	Operator of a natural gas distribution utility in Missouri	Kansas	100%
Liberty Utilities (Litchfield Park Water & Sewer) Corp.	Owner of the LPSCo System	Arizona	100%
Liberty Utilities (St. Lawrence Gas) Corp.	Owner of the St. Lawrence Gas System	New York	100%
Liberty Utilities (Canada) LP ("**Liberty Utilities Canada**")		Canada	100%
Liberty Utilities (Gas New Brunswick) LP	Owner of the New Brunswick Gas System	New Brunswick	100%

1 The Corporation holds 100% of the managing interests, with 100% of the non-managing interests held by third party partners.

2. GENERAL DEVELOPMENT OF THE BUSINESS

The Corporation owns and operates a diversified portfolio of regulated and non-regulated generation, distribution, and transmission utility assets which are expected to deliver predictable earnings and cash flows. APUC seeks to maximize total shareholder value through real per share growth in earnings and cash flow to support a growing dividend and share price appreciation.

One of APUC's financial objectives is to maintain a BBB flat investment grade credit rating. To realize that objective, APUC monitors and strives to adhere to various targets communicated by rating agencies related to their assessments of financial and business risk at APUC. These targets currently include expectations that APUC satisfies specific leverage targets and continues to generate no less than approximately its current portion of EBITDA (as determined by applicable rating agency methodologies) from APUC's Regulated Services Group. In pursuing its growth strategy, APUC evaluates investment opportunities with a view to preserving its ability to achieve these rating agency targets, which would require APUC to grow its Regulated Services Group at least in the same proportions as the Renewable Energy Group. The business mix target may from time to time require APUC to grow its Regulated Services Group or implement other strategies in order to pursue investment opportunities within its Renewable Energy Group.

The Corporation's operations are organized across two primary business units consisting of: the Regulated Services Group, which primarily owns and operates a portfolio of regulated assets in the United Stated and Canada; and the Renewable Energy Group, which primarily owns and operates a diversified portfolio of renewable generation assets. The Corporation also undertakes development activities for both business units, working with a global reach to identify, develop, acquire, or invest in renewable power generating facilities, regulated utilities and other complementary infrastructure projects. See "Description of the Business – Corporate Development Activities" for more information.

Renewable Energy Group	Regulated Services Group
Wind Power Generation Solar Generation Hydro Electric Generation Thermal Co-Generation	Electric Utilities Natural Gas Utilities Water and Wastewater Utilities Natural Gas and Electric Transmission

Renewable Energy Group

The Renewable Energy Group generates and sells electrical energy produced by its diverse portfolio of renewable power generation and clean power generation facilities primarily located across the United States and Canada. The Renewable Energy Group seeks to deliver continuing growth through development of new greenfield power generation projects and accretive acquisitions of additional electric energy generation facilities.

In addition to directly owned and operated assets, the Corporation also holds an approximate 44.2% indirect beneficial interest in Atlantica Yield plc ("**Atlantica**"), a NASDAQ-listed company that acquires, owns and manages a diversified international portfolio of contracted renewable energy, power generation, electric transmission and water assets. APUC reports its investment in Atlantica under the Renewable Energy Group.

Regulated Services Group

The Regulated Services Group operates a diversified portfolio of regulated utility systems throughout the United States and Canada serving approximately 804,000 connections. The Regulated Services Group seeks to provide safe, high quality and reliable services to its customers and to deliver stable and predictable earnings to the Corporation. In addition to encouraging and supporting organic growth within its service territories, the Regulated Services Group seeks to deliver continued growth in earnings through accretive acquisitions of additional utility systems.

2.1 Three Year History

The following is a description of the general development of the business of the Corporation over the last three fiscal years.

2.1.1 Fiscal 2017

Corporate

(i) Agreement for the Formation of AAGES and Purchase of Interest in Atlantica Yield plc

On November 1, 2017, APUC announced that it had entered into a memorandum of understanding to create AAGES to identify, develop, and construct clean energy and water infrastructure assets with a global focus. Concurrently with the agreement to create the AAGES joint venture, APUC announced that it had entered into a definitive agreement to purchase from Abengoa an indirect 25% equity interest in Atlantica (the "**Initial Atlantica Investment**") for a total purchase price of approximately $608 million, or $24.25 per ordinary share of Atlantica**,** plus a contingent payment of up to $0.60 per share payable two years after closing, subject to certain conditions.

(ii) November 2017 Offering of Common Shares

Coincident with the announcement of the Abengoa/Atlantica transaction on November 1, 2017, APUC announced a bought deal offering of Common Shares. The offering, including the exercise in full of the underwriters' over-allotment option, closed on November 10, 2017. A total of 43,470,000 Common Shares were sold at a price of C$13.25 per share for gross proceeds of approximately C$576 million.

(iii) Corporate Credit Facilities

During the third quarter of 2017, APUC's senior unsecured bilateral revolving facility was increased from C$65 million to C $165 million. This facility was terminated in July 2019. During the fourth quarter of 2017, APUC entered into a term credit agreement in the amount of $600 million with a maturity of December 21, 2018 to support the closing of its transactions with Abengoa and Atlantica, as described above. On March 7, 2018, APUC drew $600 million under this facility, which was subsequently repaid in 2019.

Renewable Energy Group

(i) Issuance of C$300 million of Senior Unsecured Debentures

On January 17, 2017, the Renewable Energy Group issued C$300 million of senior unsecured debentures bearing interest at 4.09% and with a maturity date of February 17, 2027. The debentures were sold at a price of C$99.929 per C$100.00 principal amount. Concurrent with the offering, the Renewable Energy Group entered into a cross currency swap, coterminous with the debentures, to economically convert the Canadian dollar denominated offering into U.S. dollars.

(ii) Completion of Deerfield Wind Facility

On February 21, 2017, the 149 MW Deerfield Wind Facility achieved commercial operation, on March 14, 2017, the Renewable Energy Group acquired the remaining 50% interest in the project, and on May 10, 2017, tax equity financing of approximately $167 million was completed. The project has a 20-year PPA with a local electric distribution utility.

(iii) Renewable Energy Group Credit Facilities

On April 19, 2017, the Renewable Energy Group entered into a C$150 million senior unsecured bilateral revolving credit facility with a maturity date of August 19, 2018 ("**Liberty Power Bilateral Facility**"). On October 6, 2017, the Renewable Energy Group amended its existing revolving credit facility, increasing the size to $500 million. Concurrently the Liberty Power Bilateral Facility was fully repaid and terminated.

Regulated Services Group

(i) Completion of the Empire District Electric Acquisition

On January 1, 2017, the Regulated Services Group successfully completed its acquisition of Empire for an aggregate purchase price of approximately $2.4 billion including the assumption of approximately $0.9 billion of debt. Empire is a Joplin, Missouri based regulated electric, gas and water utility serving customers in Missouri, Kansas, Oklahoma, and Arkansas.

For more detail about the Empire business, see "Description of the Business – Regulated Services Group – Description of Operations – Electric Distribution Systems" below.

(ii) Completion of Financing Related to the Empire Acquisition

On March 1, 2017, the Regulated Services Group's financing entity entered into an agreement to issue $750 million of senior unsecured notes by way of private placement. The notes are of varying maturities ranging from three to 30 years with a weighted average life of approximately 15 years and an effective weighted average interest expense of 3.6% (inclusive of interest rate hedges). The closing of the offering occurred on March 24, 2017, with the proceeds used to repay the balance of the acquisition facility for the acquisition of Empire and other existing indebtedness.

(iii) Completion of the Luning Solar Facility

On February 15, 2017, the Regulated Services Group obtained control of a 50 MW solar generating facility located in Mineral County, Nevada (the "**Luning Solar Facility**") for approximately $110.9 million. The net capital cost of the project is included in the rate base of the CalPeco Electric System as energy produced from the project is being consumed by the utility's customers.

(iv) Definitive Agreement to Acquire St. Lawrence Gas Company, Inc.

On August 31, 2017, the Regulated Services Group announced the entering into of a definitive agreement with Enbridge Gas Distribution Inc., a subsidiary of Enbridge Inc., to acquire St. Lawrence Gas Company, Inc. ("**SLG**"), a regulated natural gas distribution utility located in northern New York State, and its subsidiaries. The transaction was structured as a stock purchase in exchange for a cash purchase price of $70 million less the total amount of outstanding SLG indebtedness (which was to be assumed by the Regulated Services Group at closing and was expected to be approximately $10 million) and was subject to customary working capital adjustments**.**

2.1.2 Fiscal 2018

Corporate

(i) Acquisition of Interest in Atlantica

On March 9, 2018, the Corporation completed the formation of AAGES and the Initial Atlantica Investment closed. APUC filed a business acquisition report dated April 16, 2018 in respect of the Initial Atlantica Investment which may be found on SEDAR at www.sedar.com and on EDGAR at www.sec.gov/edgar.

On November 27, 2018, the Corporation, through its indirect subsidiary AY Holdings, completed the purchase of an additional stake of 16,530,348 ordinary shares of Atlantica from Abengoa (the "**Additional Atlantica Investment**"), for a total purchase price of $20.90 per share, comprised of a payment on closing of approximately $305 million, with up to $40 million payable at a later date contingent on satisfaction of certain conditions. APUC filed a business acquisition report dated January 22, 2019 in respect of the Additional Atlantica Investment which may be found on SEDAR at www.sedar.com and on EDGAR at www.sec.gov/edgar.

The funds for the $305 million paid on closing of the Additional Atlantica Investment were drawn on the APUC's credit agreement dated November 19, 2012, as amended from time to time (the "**Corporation Credit Facility**"). On November 28, 2018, AAGES obtained a secured credit facility in the amount of $306.5 million (the "**AAGES Secured Credit Facility**") and subscribed to a preference share ownership interest in AY Holdings, which subscription proceeds were distributed by AY Holdings to APUC and used by APUC to repay the $305 million drawn under the Corporation Credit Facility. The AAGES Secured Credit Facility is collateralized through a pledge of all of the Atlantica ordinary shares held by AY Holdings.

(ii) April 2018 Offering of Common Shares

Coincident with the initial announcement of the Additional Atlantica Investment on April 17, 2018, APUC announced an offering of 37,505,274 Common Shares at a price of C$11.85 per share for gross proceeds of approximately C$444.4 million. The Common Shares were offered and sold directly to certain institutional investors. The offering closed on April 24, 2018.

(iii) Offering of Subordinated Notes

On October 17, 2018, APUC completed an underwritten offering of 6.875% fixed-to-floating subordinated notes – Series 2018-A (the "**2018 Subordinated Notes**"). Under the offering, APUC issued $287.5 million aggregate principal amount of 2018 Subordinated Notes, including the exercise in full of the underwriters' over-allotment option. The 2018 Subordinated Notes are redeemable by APUC on or after October 17, 2023 and have a maturity date of October 17, 2078. Upon the occurrence of certain bankruptcy-related events in respect of APUC, the 2018 Subordinated Notes automatically convert into preferred shares, Series F of APUC (the "**Series F Shares**"). See "Description of Capital Structure – Subordinated Notes" for more detail on the 2018 Subordinated Notes and see "Description of Capital Structure – Preferred Shares" for more detail on the Series F Shares.

(iv) December 2018 Offering of Common Shares

On December 20, 2018, APUC completed an offering of 12,536,350 Common Shares at a price of C$13.76 per share for gross proceeds of approximately C$172.5 million. The Common Shares were offered and sold directly to certain institutional investors.

Renewable Energy Group

(i) Increase to Letter of Credit Facility

On February 16, 2018, the Renewable Energy Group increased availability under its revolving letter of credit facility to $200 million.

(ii) Completion of Great Bay Solar Facility and Amherst Island Wind Facility

On March 29, 2018, the 75 MW Great Bay Solar Facility achieved commercial operation. On June 15, 2018, the 75 MW Amherst Island Wind Facility achieved commercial operation.

Regulated Services Group

(i) Regulated Services Group Credit Facilities

On February 23, 2018, the Regulated Services Group increased availability under its senior unsecured syndicated revolving credit facility from $200 million to $500 million. The Regulated Services Group simultaneously terminated a $200 million revolving credit facility previously available to Empire.

(ii) Definitive Agreement to Acquire Enbridge Gas New Brunswick Limited Partnership

On December 3, 2018, the Regulated Services Group entered into an agreement to purchase Enbridge Gas New Brunswick Limited Partnership ("**EGNB**"), a subsidiary of Enbridge Inc., along with its general partner, for C$331 million, subject to certain customary adjustments (the "**EGNB Acquisition**"). EGNB is a regulated utility that provides natural gas to approximately 12,000 customers in 12 communities across New Brunswick and operates approximately 1,200 kilometres of natural gas distribution pipeline.

2.1.3 Fiscal 2019

Corporate

(i) At-the-Market Equity Program

On February 28, 2019, APUC announced that it established an at-the-market equity program that allows APUC to issue up to $250 million (or the equivalent in Canadian dollars) of Common Shares from treasury to the public from time to time, at APUC's discretion, at the prevailing market price when issued on the TSX, the NYSE or on any other existing trading market for the Common Shares in Canada or the United States.

(ii) Offering of Subordinated Notes

On May 23, 2019, APUC completed an underwritten offering of 6.2% fixed-to-floating subordinated notes – Series 2019-A (the "**2019 Subordinated Notes**"). Under the offering, APUC issued $350 million aggregate principal amount of 2019 Subordinated Notes. The 2019 Subordinated Notes are redeemable by APUC on or after July 1, 2024 and have a maturity date of July 1, 2079. Upon the occurrence of certain bankruptcy-related events in respect of APUC, the 2019 Subordinated Notes automatically convert into preferred shares, Series G of APUC (the "**Series G Shares**"). See "Description of Capital Structure – Subordinated Notes" for more detail on the 2019 Subordinated Notes and see "Description of Capital Structure – Preferred Shares" for more detail on the Series G Shares.

(iii) October 2019 Offering of Common Shares

In October 2019, APUC completed an underwritten marketed public offering of approximately 26.3 million of its Common Shares, including the exercise of a portion of the over-allotment option, at a price to the public of $13.50 per share, for gross proceeds of $354.4 million.

(iv) Corporate Credit Facilities

In July 2019, APUC entered into a new $500 million senior unsecured revolving credit facility with a syndicate of lenders. In conjunction with the new facility, APUC's C$165 million credit facility was terminated. In May 2019, APUC fully repaid the remaining outstanding balance of $187 million on its corporate term facility in conjunction with the issuance of the 2019 Subordinated Notes. In October 2019, APUC entered into a new $75 million uncommitted bilateral letter of credit facility.

Renewable Energy Group

(i) Issuance of C$300 million of Senior Unsecured Debentures

On January 29, 2019, APCo issued C$300 million of senior unsecured debentures bearing interest at 4.60% and with a maturity date of January 29, 2029. The debentures were sold at a price of C$999.52 per C$1,000.00 principal amount. This was the Renewable Energy Group's inaugural "green bond" offering, with the debentures being issued under the APCo Green Bond Framework, which was adopted in January 2019.

Regulated Services Group

(i) Definitive Agreement to Acquire Bermuda Electric Light Company

On June 3, 2019, APUC announced the execution of an implementation agreement with Ascendant Group Limited ("**Ascendant**") pursuant to which it is expected to acquire Ascendant and its subsidiaries. Ascendant, through its major subsidiary, Bermuda Electric Light Company Limited ("**BELCO**"), is the sole electric utility providing safe and reliable regulated electrical generation, transmission and distribution services to approximately 63,000 residents and businesses in Bermuda. Under the terms of the transaction, Ascendant's shareholders will receive $36.00 per common share, representing an aggregate share purchase price of approximately $365 million. Closing of the transaction is expected to occur in 2020 subject to customary closing conditions and the receipt of certain regulatory and government approvals in Bermuda.

(ii) Completion of the EGNB Acquisition

On October 1, 2019, the Regulated Services Group completed the EGNB Acquisition for C$331 million. The New Brunswick Gas System is a regulated utility that provides natural gas to approximately 12,000 customers in 12 communities across New Brunswick and operates approximately 1,200 kilometres of natural gas distribution pipeline.

For more detail on the New Brunswick Gas System, see "Description of the Business – Regulated Services Group – Description of Operations – Natural Gas Distribution Systems" below.

(iii) Completion of the Acquisition of SLG

On November 1, 2019, the Regulated Services Group completed the acquisition of SLG for approximately $61.8 million. The St. Lawrence Gas System is a regulated utility that provides natural gas to approximately 17,000 customers in the state of northern New York and operates approximately 1,100 km of natural gas distribution pipeline.

For more detail on the St. Lawrence Gas System, see "Description of the Business – Regulated Services Group – Description of Operations – Natural Gas Distribution Systems" below.

(iv) Definitive Agreement to Acquire New York American Water

On November 20, 2019, the Regulated Services Group entered into a stock purchase agreement with American Water Works Company, Inc. ("**American Water**"), to purchase American Water's regulated operations in the State of New York ("**New York American Water**") for a purchase price of $608 million, subject to customary adjustments. New York American Water is a regulated water and wastewater utility serving over 125,000 customer connections across seven counties in southeastern New York. Operations include approximately 1,270 miles of water mains and distribution lines with 98% of customers in Nassau County on Long Island. Closing of the transaction is expected to occur sometime in 2021 subject to customary closing conditions and the receipt of regulatory approval.

(v) Regulated Services Group Commercial Paper Program

In July 2019, the Regulated Services Group established a commercial paper program pursuant to which the Regulated Services Group can issue up to $500 million of unsecured notes with maturities not exceeding 270 days from the issuance date.

2.1.4 Recent Developments – 2020

Renewable Energy Group

(i) Increase to Letter of Credit Facility

On February 24, 2020, the Renewable Energy Group increased availability under its revolving letter of credit facility to $350 million.

Regulated Services Group

(i) Issuance of C$200 million of Senior Unsecured Debentures

On February 14, 2020, Liberty Utilities Canada issued C$200 million of senior unsecured debentures bearing interest at 3.315% and with a maturity date of February 14, 2050. The debentures were issued at par.

3. DESCRIPTION OF THE BUSINESS

3.1 Renewable Energy Group

The Renewable Energy Group generates and sells electrical energy produced by its diverse portfolio of renewable power generation and clean power generation facilities located across the United States and Canada. The Renewable Energy Group seeks to deliver continuing growth through development of new greenfield power generation projects and accretive acquisitions of additional electrical energy generation facilities.

The Renewable Energy Group owns and operates hydroelectric, wind, solar and thermal facilities with a combined gross generating capacity of approximately 1.5 GW. Approximately 84% of the electrical output is sold pursuant to long-term contractual arrangements which as of December 31, 2019 had a production-weighted average remaining contract life of approximately 14 years.

3.1.1 Description of Operations

Wind Power Generating Facilities

(i) Production Method

The energy of the wind can be harnessed for the production of electricity through the use of wind turbines. A wind energy system transforms the kinetic energy of wind into electrical energy that can be delivered to the electricity distribution system for use by energy consumers. When the wind blows, large rotor blades on the wind turbines are rotated, generating energy that is converted to electricity. Most modern wind turbines consist of a rotor mounted on a shaft connected to a speed increasing gear box and high-speed generator. Monitoring systems control the angle of and power output from the rotor blades to ensure that the rotor blades are turned to face the wind direction, and generally to monitor the wind turbines installed at a facility. The Renewable Energy Group owns and operates 12 wind power generating facilities with a combined gross generating capacity of approximately 1,130 MW.

(ii) Principal Markets and Distribution Methods

The principal markets for the Renewable Energy Group's significant operational wind facilities in Canada are Manitoba (the St. Leon Wind Facility) and Ontario (the Amherst Island Wind Facility). The electricity generated by the wind turbines is transmitted to the transmission system of the purchaser, being Manitoba Hydro in the case of the St. Leon Wind Facility and the IESO in the case of the Amherst Island Wind Facility. The principal markets for the Renewable Energy Group's wind facilities in the United States are PJM, MISO and ERCOT.

(iii) Selected Facilities

(1) St. Leon Wind Facility

The St. Leon Wind Facility is a 103.9 MW wind powered electrical generating facility located near St. Leon, Manitoba, approximately 150 km southwest of Winnipeg. The St. Leon Wind Facility entered into a PPA with Manitoba Hydro effective June 17, 2006 under which all electricity produced is sold to Manitoba Hydro. The term of the PPA is 20 years, with a price renewal term of up to an additional five years.

(2) Shady Oaks Wind Facility

The Shady Oaks Wind Facility is a 109.5 MW wind powered electrical generating facility located in Lee County, Illinois, approximately 80 km west of Chicago. The Shady Oaks Wind Facility is party to a 20-year power sales contract with the largest electric utility in the state of Illinois, Commonwealth Edison. The power sales contract is structured to hedge the preponderance of the Shady Oaks Wind Facility's production volume against exposure to PJM ComEd Hub current spot market rates. Annual production is subject to contingent curtailment based on certain regulatory constraints of the electricity purchaser. Ancillary services, including capacity, reactive power and RECs, are sold into the PJM market.

(3) Sandy Ridge Wind Facility

The Sandy Ridge Wind Facility is a 50 MW wind powered electrical generating facility located in Centre County, Pennsylvania, 180 km east of Pittsburgh. Sandy Ridge Wind, LLC is party to a long-term energy production hedge (a "**Primary Energy Production Hedge**") with respect to the majority of production with J.P. Morgan Ventures Energy Corporation ("**JPMVEC**") having a term of 10 years beginning January 1, 2013 and is also party to energy production hedges with another third party for production from 2023 to 2028. Ancillary services, including capacity and RECs, are sold into the PJM market.

(4) Minonk Wind Facility

The Minonk Wind Facility is a 200 MW wind powered electrical generating facility located near Minonk, IL, approximately 200 km southwest of Chicago, Illinois. The Renewable Energy Group first acquired an indirect interest in the Minonk Wind Facility on December 10, 2012. Minonk Wind, LLC is party to a Primary Energy Production Hedge with JPMVEC, having a term of 10 years beginning January 1, 2013 and is also party to energy production hedges with another third party for production from 2023 to 2024. Ancillary services, including capacity, reactive power and RECs, are sold into the PJM market.

(5) Senate Wind Facility

The Senate Wind Facility is a 150 MW wind powered electrical generating facility located near Graham, Texas, approximately 200 km west of Dallas, Texas. Senate Wind, LLC is party to a Primary Energy Production Hedge with JPMVEC, having a term of 15 years beginning January 1, 2013. RECs are sold into the ERCOT market.

(6) Odell Wind Facility

The Odell Wind Facility is a 200 MW wind powered electrical generating facility located near Windom, Minnesota, approximately 230 km southwest of Minneapolis, Minnesota. Odell Wind Farm LLC has entered into a PPA with an investment grade utility under which all electricity and RECs produced at the facility are sold. The term of the PPA is 20 years.

(7) Deerfield Wind Facility

The Deerfield Wind Facility is a 149 MW wind powered electrical generating facility located in central Michigan, approximately 180 km north of Detroit, Michigan. All energy, capacity, and RECs produced at the facility are sold to a local electric distribution utility pursuant to a 20-year PPA.

(8) Amherst Island Wind Facility

The Amherst Island wind facility is a 75 MW wind powered electric generating facility located on Amherst Island near the village of Stella, approximately 15 km southwest of Kingston, Ontario (the "**Amherst Island Wind Facility**"). The electricity generated by the project is being sold under a 20-year PPA awarded as part of the IESO FIT program. The Renewable Energy Group's interest in the project was previously held in a joint venture with the EPC contractor. In April 2019, the Renewable Energy Group acquired the balance of the joint venture interest not previously owned and in May 2019 entered into a separate partnership, in which the Corporation holds a majority interest, with Atlantica to hold the Amherst Island Wind Facility.

Solar Power Generating Facilities

(i) Production Method

Solar power is the conversion of sunlight into electricity, either directly using photovoltaics or indirectly using concentrated solar power. The Corporation's solar generation facilities utilize photovoltaics which convert light into electric current using the photovoltaic effect. The array of a photovoltaic power system produces direct current power which fluctuates with the sunlight's intensity. For practical use, commercial installations convert this direct current generated power to alternating current through the use of inverters. The Renewable Energy Group owns and operates four solar power generating facilities with a combined gross generating capacity of approximately 115 MW.

(ii) Principal Markets and Distribution Methods

The principal markets for the Renewable Energy Group's operational solar facilities are Ontario, California and PJM. The electricity generated by the solar panels is transmitted via electrical collection lines to the facility substation for subsequent delivery to the distribution/transmission system under control of the local distribution company and the ISO.

(iii) Selected Facilities

(1) Bakersfield I Solar Facility

The Bakersfield I Solar Facility is a 20 MW ground mounted photovoltaic solar powered electric generating facility that uses single axis trackers to optimize the site's generating efficiency. The site is located near Bakersfield, California, 150 km northwest of Los Angeles, California. The Bakersfield I Solar Facility achieved commercial operation in April 2015 and has a fixed rate PPA with an investor-owned utility with a term of 20 years from commencement of commercial operation.

(2) Great Bay Solar Facility

The Great Bay Solar Facility is a 75 MW solar powered electric generating facility comprising four sites located in Somerset County in southern Maryland. All energy from the project is sold to the U.S. Government Services Administration pursuant to a 10-year PPA, with a 10 year extension option. All RECs from the project are retained by the project company and sold into the Maryland market.

Hydroelectric Generating Facilities

(i) Production Method

A hydroelectric generating facility consists of a number of key components, including a dam, intake structure, electromechanical equipment consisting of a turbine(s) and a generator(s). A dam structure is required to create or increase the natural elevation difference between the upstream reservoir and the downstream tailrace, as well as to provide sufficient depth within the reservoir for an intake. Water flows are conveyed from the upstream reservoir to the generating equipment via a penstock or headrace canal and an intake structure. Turbine(s) and generator(s) transform the hydraulic energy into electrical energy. The water which has flowed through the hydraulic turbine(s) is discharged back to the natural watercourse. A transmission line is often required to interconnect a facility with the grid. The majority of hydroelectric generating facilities are also equipped with remote monitoring equipment, which allows the facility to be monitored and operated from a remote location. The Renewable Energy Group owns and operates 18 hydroelectric power generating facilities with a combined gross generating capacity of approximately 115 MW.

(ii) Principal Markets and Distribution Methods

The principal markets in which the Renewable Energy Group operates hydroelectric generating facilities in Canada are Alberta, Ontario, New Brunswick and Québec. In the U.S., the principal market is Maine. The majority of generated hydroelectricity is conveyed from the relevant facility to the purchasers under the terms of long-term PPAs. The electricity is generally transferred by transmission line from the generating facility to the delivery point for the purchaser, and it is distributed through the grid to end user customers of the purchaser.

(iii) Selected Facility

(1) Tinker Hydro Facility

The Tinker Hydro Facility is located approximately 8 km north of Perth-Andover, New Brunswick and is situated near the mouth of the Aroostook River. The facility has a total nameplate capacity of approximately 34.5 MW.

As part of the generation assets in New Brunswick, the Corporation owns an electrical transmission system used to interconnect the Tinker Hydro Facility to the New Brunswick transmission network, provide transmission service to Perth Andover Electric Light Commission, and provide export/import capacity between Maine and New Brunswick.

The output of the Tinker Hydro Facility is actively marketed together with any applicable environmental attributes less any associated transportation costs. Additional energy and applicable environmental attributes are purchased from the market to supplement the energy generated from the Tinker Hydro Facility in order to service customer demand.

Thermal (Cogeneration) Electric Generating Facilities

(i) Production Method

Cogeneration is the simultaneous production of electricity and thermal energy such as hot water or steam from a single fuel source. The steam produced is normally required by an associated or nearby commercial facility, while the electricity generated is sold to a utility or used within the facility. Cogeneration provides facilities with greater efficiency, greater reliability and increased process flexibility than conventional generation methods. The Renewable Energy Group owns and operates two thermal electric power generating facilities with a combined gross generating capacity of approximately 130 MW.

(ii) Principal Markets and Distribution Methods

The principal markets for the Corporation's cogeneration facilities are California and Connecticut. The electricity produced from these facilities is conveyed from the relevant facility to the electricity markets either under the terms of long-term contracts or according to ISO rules. In addition to grid sales of electricity and power, electricity and thermal energy are also sold to onsite or adjacent third-party thermal host facilities for use in production.

(iii) Selected Facilities

(1) Sanger Thermal Facility

The Sanger thermal cogeneration facility is a 56 MW natural gas-fired generating facility located in Sanger, California. The facility has a firm capacity agreement with an investor-owned utility expiring in 2021. The agreement calls for delivery of 38 MW of firm capacity. Following the expiry of the current firm capacity agreement, a new offtake agreement for 19 MW with a local municipality will continue through to the end of 2021.

(2) Windsor Locks Thermal Facility

The Windsor Locks thermal cogeneration facility (the "**Windsor Locks Thermal Facility**") is a 71 MW natural gas-fired generating facility located in Windsor Locks, Connecticut. The Windsor Locks Thermal Facility supplies thermal steam energy and a portion of electrical generation to Ahlstrom Corporation pursuant to a ground lease and an energy services agreement. Payments under the energy services agreement are fully indexed to the cost of natural gas consumed by the Windsor Locks Thermal Facility. The additional installed capacity at the site is committed to the ISO-NE market in the day ahead energy market, and the capacity and reserve markets as appropriate.

3.1.2 Specialized Skill and Knowledge

The Renewable Energy Group's employees have extensive experience in the independent power industry in Canada and the United States. The production of energy from all facilities requires specialized skill and knowledge in relation to such facilities and their component parts, and the Renewable Energy Group employs various personnel, and occasionally uses outside contractors, who have such skill and knowledge.

3.1.3 Competitive Conditions

Deregulation has increased the demand for privately generated power from a variety of sources, including fossil fuels, waste, wind, water and solar. With deregulation and opening of competition in the electricity marketplace, there may continue to be an increased opportunity for the energy customer to choose the type of generation producing the electricity.

Unlike electricity generated by fossil fuels such as natural gas and coal which are subject to potentially dramatic and unexpected price swings due to disruptions in supply or abnormal changes in demand, the supply of hydroelectric, wind and solar power is generally not subject to commodity fuel price volatility or risk. In addition, generation of the above forms of renewable power generally does not involve significant ongoing capital and operating costs to ensure strict compliance with environmental regulations, which is a significant advantage over power generated by burning waste or utilizing landfill gases.

Taking into account capital costs, wind and solar power has generally been more expensive than traditional forms of generated power. However, in recent years costs have decreased with the increased demand for renewable energy, market competitiveness and improvements in generating technology. With production tax incentives, investment tax incentives, RPS and improved equipment capacity factors, both wind and solar energy have achieved parity with market pricing for electricity in many jurisdictions.

The Renewable Energy Group believes that future opportunities for power generation projects will continue to arise given that many jurisdictions continue to increase targets for renewable and other clean power generation projects.

The Renewable Energy Group is positioned to take advantage of this demand for increased renewable energy, given that a significant portion of its assets are from renewable sources.

3.1.4 Cycles and Seasonality

(i) Wind Power Generating Facilities

The Renewable Energy Group's wind generation facilities are impacted by seasonal fluctuations and year to year variability of the wind resource. During the fall and spring periods, winds are generally stronger than during the summer period. The ability of these facilities to generate income may be impacted by naturally occurring changes in wind patterns and wind strength.

(ii) Solar Power Generating Facilities

The Renewable Energy Group's solar generation facilities are impacted by seasonal fluctuations and year to year variability in solar radiance. For instance, there are more daylight hours in the summer than there are in the winter, resulting in higher production in the summer months. The ability of these facilities to generate income may be impacted by naturally occurring changes in solar radiance.

(iii) Hydroelectric Generating Facilities

The Renewable Energy Group's hydroelectric operations are impacted by seasonal fluctuations and year to year variability of the available hydrology. These assets are primarily "run-of-river" and as such fluctuate with natural water flows. During the winter and summer periods, flows are generally lower, while during the spring and fall periods flows are generally higher. The ability of these assets to generate income may be impacted by changes in water availability or other material hydrologic events within a watercourse. Year to year, the level of hydrology varies impacting the amount of power that can be generated in a year.

The Renewable Energy Group attempts to mitigate the above noted natural resource fluctuation risks by acquiring or developing generating stations in different geographic locations.

3.2 Regulated Services Group

The Regulated Services Group operates a diversified portfolio of rate-regulated utilities throughout Canada and the United States that, as at December 31, 2019, provided distribution services to approximately 804,000 connections in the natural gas, electric, water and wastewater sectors, with an approximate regional breakdown as follows.

	West	Central	East
Natural gas distribution	—	128,500	240,500
Electrical distribution	50,000	172,500	44,500
Water distribution	97,000	26,000	—
Wastewater collection	43,000	2,000	—
Total	**190,000**	**329,000**	**285,000**

The Regulated Services Group's electrical distribution utility systems and related transmission and generation assets are located in the states of Arkansas, California, Kansas, Missouri, New Hampshire, and Oklahoma. The Regulated Services Group's natural gas distribution utility systems are located in the province of New Brunswick and the states of Georgia, Illinois, Iowa, Massachusetts, Missouri, New Hampshire and New York. The Regulated Services Group's water distribution and wastewater collection utility systems are located in the states of Arizona, Arkansas, California, Illinois, Missouri and Texas. The Regulated Services Group also owns and manages generating assets with a gross capacity of approximately 1.7 GW and has investments in generating assets with approximately 0.3 GW of net generation capacity.

3.2.1 Description of Operations

Water Distribution and Wastewater Collection Systems

(i) Method of Providing Services and Distribution Methods

A water utility services company provides regulated utility water supply and/or wastewater collection and treatment services to its customers.

A water utility sources, treats and stores potable water and subsequently distributes it to its customers through a network of buried pipes (distribution mains). The raw water for human consumption is sourced from the ground and extracted through wells or from surface water such as lakes or rivers. The water is treated to potable water standards that are specified in federal and state regulations and which are typically administered and enforced by a state or local agency. Following treatment, the water is either pumped directly into the distribution system or pumped into storage reservoirs from which it is subsequently pumped into the distribution system. This system of wells, pumps, storage vessels and distribution infrastructure is owned and maintained by the private utility. The fees or rates charged for water are comprised of a fixed charge component plus a variable fee based on the volume of water used. Additional fees are typically chargeable for other services such as establishing a connection, late fees and reconnects.

A wastewater utility collects wastewater from its customers and transports it through a network of collection pipes, lift stations and manholes to a centralized facility where it is treated, rendering it suitable for discharge to the environment or for reuse, usually as irrigation. The wastewater is ultimately delivered to a treatment plant. Primary treatment at the plant consists of the screening out of larger solids, floating material and other foreign objects and, at some facilities, grit removal. These removed materials are hauled to a landfill. Secondary treatment at the plant consists of biological digestion of the organic and other impurities which is performed by beneficial bacteria in an oxygen enriched environment. Excess and spent bacteria are collected from the bottom of the tanks, digested and/or dewatered, and the resulting solids are sent to landfill or to land application as a soil amendment. The treated water, referred to as “effluent”, is then used for irrigation or groundwater recharging or is discharged by permit into adjacent surface water. The standards to which this wastewater is treated are specified in each treatment facility’s operating permit and the wastewater is routinely tested to ensure its continuing compliance therewith. The effluent quality standards are based on federal and state regulations which are administered, and continuing compliance is enforced by the state agency to which federal enforcement powers are delegated.

(ii) Principal Markets and Regulatory Environments

The Regulated Services Group’s water and wastewater facilities are located in the United States in the states of Arizona, Arkansas, California, Illinois, Missouri and Texas. The water and wastewater utilities are generally subject to regulation by the public utility commissions of the states in which they operate. The respective public utility commissions have jurisdiction with respect to rate, service, accounting procedures, issuance of securities, acquisitions and other matters. These utilities generally operate under cost-of-service regulation as administered by these state authorities. The utilities generally use a historic or forward-looking test year in the establishment of rates for the utility and pursuant to this method the determination of the rate of return on approved rate base, recovery of depreciation on plant, together with all reasonable and prudent operating costs, establishes the revenue requirement upon which each utility’s customer rates are determined.

Rate cases ensure that a particular facility appropriately recovers its operating costs and has the opportunity to earn a rate of return on its capital investment as allowed by the regulatory authority under which the facility operates. The Corporation monitors the rates of return on each of its water and wastewater utility investments to determine the appropriate time to file rate cases in order to ensure it earns the regulatory approved rate of return on its investments. Rates are approved by the agency to provide the utility the opportunity, but not the guarantee, to earn a reasonable return on its investment after recovering its prudently incurred operating expenses.

(iii) Selected Facilities

(1) LPSCo System

The LPSCo System, located in and around the city of Goodyear 15 miles west of Phoenix, Arizona has a service area that includes the City of Litchfield Park and sections of the cities of Goodyear and Avondale as well as portions of unincorporated Maricopa County. The wastewater system’s Palm Valley Water Reclamation Facility has permitted treatment capacity of 6.5 million gallons per day.

(2) Liberty Park Water System

Liberty Utilities (Park Water) Corp. ("**Liberty Park Water**") owns and operates two regulated water utilities engaged in the production, treatment, storage, distribution and sale of water in Southern California. Liberty Park Water provides, owns and operates the water system in central Los Angeles. Liberty Utilities (Apple Valley Ranchos Water) Corp. (wholly-owned by Liberty Park Water) owns and operates the water system in Apple Valley (the "**Liberty Park Water System**").

Electric Distribution Systems

(i) Method of Providing Services and Distribution Methods

Electric distribution is the final stage in the delivery system of providing electricity to end users. An electric distribution utility sources and distributes electricity to its customers through a network of buried or overhead lines. The electricity is sourced from power generation facilities. The electricity is transported from the source(s) of generation at high voltages through transmission lines and is then reduced through transformers to lower voltages at substations. The electricity from the substations is then delivered through distribution lines to the customers where the voltage is again lowered through a transformer for use by the customer.

The rates charged for electric distribution service are comprised of a fixed charge that recovers customer related costs, such as meter readings, and a variable rate component that recovers the cost of generation, transmission and distribution. Other revenues are comprised of fees for other services such as establishing a connection, late fee, reconnections, and energy efficiency programs.

The electrical distribution utilities located in Arkansas, California, Kansas, Missouri, New Hampshire and Oklahoma are subject to state regulation and rates charged by these utilities must be reviewed and approved by their respective state regulatory authorities.

(ii) Principal Markets and Regulatory Environments

The Regulated Services Group operates electrical distribution systems in the states of Arkansas, California, Kansas, Missouri, New Hampshire and Oklahoma under a cost-of-service methodology. The utilities use either an historical test year, adjusted pro-forma for known and measurable changes, in the establishment of their rates, or prospective test years based on expenses expected to be incurred in future periods. Pursuant to these methods, the revenue requirement upon which rates are based is determined by applying an approved return on rate base, and adding depreciation, operating expenses and administrative and general expenses.

Rate cases ensure that a particular utility recovers its operating costs and has the opportunity to earn a reasonable rate of return on its capital investment as allowed by the regulatory authority under which the utility operates. The Corporation monitors the rates of return on its utility investments to determine the appropriate times to file rate cases in order to ensure it earns a reasonable rate of return on its investments. In the case of the CalPeco Electric System, a rate case filing is mandatory every three years.

(iii) Selected Facilities

(1) CalPeco Electric System

The CalPeco Electric System provides electric distribution service to the Lake Tahoe basin and surrounding areas. The service territory, centered on a highly popular tourist destination, has a customer base spread throughout Alpine, El Dorado, Mono, Nevada, Placer, Plumas and Sierra Counties in northeastern California. CalPeco Electric System's connection base is primarily residential. Its commercial connections consist primarily of ski resorts, hotels, hospitals, schools and grocery stores.

The Corporation has entered into a multi-year services agreement with NV Energy that commenced in January 2016 and will expire at the end of 2020. The services agreement obligates NV Energy to use commercially reasonable efforts to supply the CalPeco Electric System with sufficient renewable power to, when combined with the output of the Luning Solar Facility and the Turquoise Solar Facility, satisfy the current California Renewables Portfolio Standard requirement for the term of the services agreement. The parties are currently discussing a renewal of this agreement, which may contemplate additional renewable energy development. The CalPeco Electric System will seek approval from CPUC to recover the costs it will incur under the renewal of this agreement. The CalPeco Electric System has authorization for rate recovery of the costs that the CalPeco Electric System has or will incur to acquire, own and operate the Luning Solar Facility and the Turquoise Solar Facility.

(2) Granite State Electric System

The Granite State Electric System provides distribution service in southern and northwestern New Hampshire, centered around operating centres in Salem in the south and Lebanon in the northwest. The Granite State Electric System's customer base consists of a mixture of residential, commercial and industrial customers.

The Granite State Electric System is required to provide electric commodity supply for all customers who do not choose to take supply from a competitive supplier ("**Energy Service**") in the New England power market and is allowed to fully recover its costs for the provision and administration of Energy Service under the Energy Service Adjustment Factor, as approved by the NHPUC. The Granite State Electric System must file with the NHPUC twice a year to adjust for market prices of power purchased and is also subject to FERC regulation.

(3) Empire District Electric System

Based in Joplin, Missouri, Empire is a regulated utility providing electric, natural gas and water service in parts of Missouri, Kansas, Oklahoma and Arkansas. As part of its electric segment, it provides water service to three towns in Missouri. The vertically-integrated regulated electricity operations of Empire represent the majority of its operating revenues and assets. The largest urban area served is the city of Joplin, Missouri, and its immediate vicinity. Empire also operates a fibre optics business. The utility portions of the business are subject to regulation by the MPSC, the KCC, the OCC, the APSC and FERC.

Natural Gas Distribution Systems

(i) Method of Providing Services and Distribution Methods

Natural gas is a fossil fuel composed almost entirely of methane (a hydrocarbon gas) usually found in deep underground reservoirs formed by porous rock. In making its journey from the wellhead to the customer, natural gas may travel thousands of miles through interstate pipelines owned and operated by pipeline companies. Along the route, the natural gas may be stored underground in depleted oil and gas wells or other natural geological formations for use during seasonal periods of high demand. Interstate pipelines interconnect with other pipelines and other utility systems and offer system operators flexibility in moving the gas from point to point. The interstate pipeline companies are regulated by the FERC. Typically, the distribution network operates pipelines (including transmission and distribution pipelines), gate stations, district regulator stations, peak shaving plants and natural gas meters. The gas distribution utilities owned by the Regulated Services Group are subject to state regulation and rates charged by these facilities may be reviewed and altered by the state regulatory authorities from time to time.

(ii) Principal Markets and Regulatory Environments

The Regulated Services Group owns and operates natural gas distribution systems, under cost-of-service regulation in the states of Illinois, Iowa, Missouri, Georgia, Massachusetts, New Hampshire and New York and the province of New Brunswick. In establishing rates, the natural gas utilities use either a historical test year that is adjusted on a pro-forma basis for known and measurable changes or a prospective test year based on expenses expected to be incurred in a future period, which is the methodology utilized in New Brunswick and Illinois. Pursuant to the prospective test year method, the revenue requirement upon which rates are based is determined by applying an approved return on rate base, and adding depreciation, operating expenses, and administrative and general expenses.

Rate cases ensure that a particular facility appropriately recovers its operating costs and has the opportunity to earn a reasonable rate of return on its capital investment as allowed by the regulatory authority under which the facility operates. The Corporation monitors the rates of return on its utility investments to determine the appropriate times to file rate cases, with the goal of earning a reasonable rate of return on its investments.

(iii) Selected Facilities

(1) EnergyNorth Gas System

The EnergyNorth Gas System is a regulated natural gas utility providing natural gas distribution services in 30 communities covering five counties in New Hampshire. Its franchise service area includes the communities of Nashua, Manchester and Concord. The EnergyNorth Gas System's customer base consists of a mixture of residential, commercial, industrial and transportation customers.

In its rate case completed during 2018, the rates of the EnergyNorth Gas System were authorized to be decoupled, which means that, going forward, fluctuations in weather will have less impact on revenues.

(2) Empire District Gas System

EDG is engaged in the distribution of natural gas in Missouri serving customers in northwest, north central and west central Missouri. A PGA allows EDG to recover from its customers, subject to audit and final determination by regulators, the cost of purchased gas supplies and related carrying costs associated with EDG's use of natural gas financial instruments to hedge the purchase price of natural gas. This PGA allows EDG to make rate changes periodically (up to four times) throughout the year in response to weather conditions and supply demands, rather than in one possibly extreme change per year.

(3) Peach State Gas System

The Peach State Gas System is a regulated natural gas system providing natural gas distribution services in 13 communities covering six counties in Georgia. Its franchise service area includes the communities of Columbus, Gainesville, Waverly Hall, Oakwood, Hamilton and Manchester. The Peach State Gas System's customer base consists of a mixture of residential, commercial, industrial and transportation customers.

The Peach State Gas System's rates have been reviewed and updated annually through a tariff provision called the Georgia Rate Adjustment Mechanism. This mechanism allowed for the annual review of cost recoveries and the setting of rate base returns with a target of 10.7% return on equity and a range of 10.5% to 10.9%. In early 2020, Peach State Gas System will file its first rate case which will reset the return on equity target and range. In its rate case filing, Peach State expects to request the continuation of the Georgia Rate Adjustment Mechanism.

Georgia allows full recovery of all gas costs (including commodity price, transportation, reservation and demand costs, hedging costs, storage costs).

(4) New England Gas System

The New England Gas System is a regulated natural gas utility providing natural gas distribution services in six communities located in the southeastern portion of Massachusetts. The New England Gas System's customer base consists of a mixture of residential, commercial, and industrial customers.

The cost of gas is fully recoverable from customers through the Gas Adjustment Factor ("**GAF**") when billed to "firm" gas customers included in approved tariffs by the MDPU. The GAF is adjusted twice annually and more frequently under certain circumstances.

(5) Midstates Gas Systems

The Midstates Gas Systems own regulated natural gas utilities providing natural gas distribution services to approximately 203 communities in the states of Illinois, Iowa and Missouri, with a mix of residential, commercial, industrial and transportation customers. The franchise service area includes the communities of Virden, Vandalia, Harrisburg and Metropolis in Illinois, Keokuk in Iowa, and Butler, Kirksville, Canton, Hannibal, Jackson, Sikeston, Malden and Caruthersville in Missouri.

Illinois, Iowa and Missouri allow full recovery of all gas costs (including commodity price, transportation, reservation and demand costs, hedging costs, and storage costs). The rate is adjusted monthly in Illinois and Iowa with an annual reconciliation. In Missouri, the rate is adjusted annually with allowance to file quarterly. In Missouri and Illinois, mechanisms exist to allow for the recovery of the revenue requirement approved by the regulator. In Missouri, the weather normalization adjustment mechanism allows for the adjustment in revenue due to weather and in Illinois, the volume balancing adjustment mechanism allows for the recovery of revenue due to variances in the volume of gas used.

(6) New Brunswick Gas System

The New Brunswick Gas System is regulated by the NB Energy Board and has a distribution network that includes approximately 1,200 kilometers of natural gas pipeline, and provides service to customers in 12 communities in New Brunswick. The NB Energy Board's regulatory activities in the natural gas sector are primarily in relation to the New Brunswick Gas System which is the exclusive holder of the natural gas distribution franchise for the Province of New Brunswick, which expires in 2044 and is extendable for an additional 25 year period.

For rate cases, the NB Energy Board can review all facets of the operations but primarily focuses on the approval of the previous calendar year's regulatory financial statements, future test year budgets and other decisions like customer retention and incentive programs, load retention rate proposals, return on equity, debt structure and rate class reviews.

(7) St. Lawrence Gas System

The St. Lawrence Gas System is a regulated natural gas utility in the business of distributing natural gas to customers in northern New York State across St. Lawrence County, Franklin County and a portion of Lewis County. The St. Lawrence Gas System's customer base consists of a mixture of residential, commercial, industrial, and electric generation customers.

In a traditional rate case filing, the filing includes historical operating results (test year) and a 12-month forecast for the period the rates will be in effect (rate year). More commonly, the St. Lawrence Gas System will endeavor to settle the rate case filing, in which case there will be a multi-year plan in which the rate base and revenue requirement is adjusted for subsequent years within the plan. The St. Lawrence Gas System has a revenue decoupling mechanism which applies to residential and commercial customers within sales and transportation service types. This mechanism reconciles actual delivery service revenue to allowed delivery service revenues, which effectively adjusts the revenue for weather, energy efficiency, and customer numbers.

Natural Gas and Electric Transmission

(i) Method of Providing Services and Transmission Methods

Pipelines offer a variety of services under their FERC tariffs to include firm and interruptible transportation, along with other services to provide commercial markets additional flexibility. Some examples of these types of services would be park and loan, pooling and balancing services. In addition, firm service tariff features would also provide additional features to support secondary market activity to include, but not limited to capacity assignment, capacity releases, segmentation and renewal options.

Electric transmission is the bulk transportation of generated electricity over long distances from a generating site, such as a power plant, to an electrical substation. Transmission lines move large amounts of power at a high voltage level to a substation for voltage step-down and on to a lower voltage distribution network resulting in electricity delivered to homes and businesses. Transmission services obtained through the FERC-governed OATT include network and point-to-point transmission service along with other ancillary services. Some examples of these types of services would be spinning and non-spinning reserves, black-start capability, regulation and voltage support and system control and dispatch.

(ii) Principal Markets and Regulatory Environments

Interstate natural gas pipeline transmission assets are regulated primarily by the FERC under the Natural Gas Act. Under this framework, this agency authorizes and certifies all construction, and or abandonment of interstate gas pipeline facilities, requires certificate holders, once operational, to establish and maintain an OATT and publicly post capacity available for transportation, and the agency periodically reviews, under just and reasonable standards, the tariff rates to be charged by the certificate holder. In addition, the FERC prescribes operating and safety standards to be followed along with other federal agencies such as Department of Transportation and the Occupational Safety and Health Administration.

Empire's transmission rates and services and electric wholesale sales of electric energy in interstate commerce and its facilities are subject to the jurisdiction of the FERC, under the Federal Power Act. Wholesale rate recovery of transmission costs, as with wholesale rate recovery of any other cost, is subject to the FERC review.

The operations and rates of APUC's transmission facility in New Brunswick are regulated by the NB Energy Board. It is entitled to recover the transmission revenue requirement, pursuant to the transmission tariff administered by New Brunswick Power Corporation. Any increase to its revenue requirement would result in an increase to the transmission rates under the OATT.

(iii) Selected Facilities

(1) Empire Transmission Facilities

The Empire electric transmission facilities are located within a four state area of Missouri, Kansas, Oklahoma and Arkansas and primarily consist of 22 miles of 345 kV lines, 405 miles of 161 kV lines, 750 miles of 69 kV lines and 82 miles of 34.5 kV lines.

Empire is a member of the SPP which spans an area from the Canadian border in Montana and North Dakota in the north to parts of New Mexico, Texas and Louisiana in the south. The transmission facilities are offered for service under an OATT approved by the FERC and administered by SPP. Service requests are placed in the SPP Open Access Same-Time Information System (OASIS) and is evaluated by SPP for available capacity. SPP determines who is offered available transmission capacity subject to the SPP Tariff and SPP Market Rules and is offered on a non-discriminatory basis. Service requests can be either point-to-point or network service, where network service is used for serving electric load. Empire is subject to four different states regulatory bodies, the Midwest Reliability Organization regional entity for NERC compliance, SPP Market Rules, and the FERC.

3.2.2 Specialized Skill and Knowledge

The Regulated Services Group requires specialized knowledge of its utility systems, including electrical, gas, water and wastewater. Upon acquiring a new utility system, the Regulated Services Group will typically retain the existing employees with such specialized skill and knowledge. In addition, the Regulated Services Group will add, when required, additional trained utility personnel at its corporate offices to support the expanded portfolio of utility assets.

3.2.3 Competitive Conditions

The Regulated Services Group's utility businesses have geographic monopolies in their service territories. The Regulated Services Group has developed in-house regulatory expertise in order to effectively interact with the state regulators in the various jurisdictions in which it operates. The Regulated Services Group believes that the relationship with regulators is unique to each state and therefore is best delivered by local managers who work in the service territory. The local regulatory teams meet with regulatory agencies on a regular basis to review regulatory policies, service delivery strategies, operating results and rate making initiatives.

3.2.4 Cycles and Seasonality

(i) Water and Wastewater Systems

Demand for water is affected by weather conditions including temperature and precipitation. For certain service areas, water usage during the summer months is significantly greater than the winter months primarily because of the outdoor water usage associated with irrigation as well as the water used for other purposes including swimming pools and cooling systems.

When either the amount or frequency of precipitation is significantly above average, water usage may decrease, resulting in reduced operating revenues. Drought conditions arise when the amount and frequency of precipitation is significantly below average for an extended period of time. Drought conditions may lead to voluntary and mandatory restrictions on water usage and thereby impact the Corporation's ability to recover its fixed costs in delivering clean, safe, and reliable water to customers at reasonable rates.

The Regulated Services Group attempts to mitigate the risk of reduced water usage by seeking regulatory mechanisms in rate case proceedings. Certain regulatory jurisdictions have approved regulatory mechanisms that address changes in the actual recorded water usage as compared to the authorized water usage. For example, for the Liberty Park Water System, the water revenue adjustment mechanism tracks the difference between the CPUC authorized commodity revenue and the actual recorded commodity revenue to ensure recovery of fixed costs that are recovered through the commodity or quantity charge. The purpose of the mechanism is to de-couple water usage from revenues. Not all regulatory jurisdictions in which the Regulated Services Group operates have approved mechanisms to mitigate reduced water usage and the resulting reduction in revenues.

(ii) Electricity Systems

The CalPeco Electric System's demand for energy sales fluctuate depending on weather conditions. The CalPeco Electric System is a winter-peaking utility. Above normal snowfall in the Lake Tahoe area brings more tourists and increases demand for electricity. The CalPeco Electric System has implemented a BRRBA rate mechanism that removes the annual variations of recorded revenues to ensure that it recovers its authorized base revenues (gross revenues less fuel, purchased power, and other non-base revenues) over each rate case cycle.

The Granite State Electric System experiences peak loads in both the winter and summer seasons, due to heating and cooling loads associated with New England weather. The competitive market for power supply is managed by the ISO-NE. The Energy Service price for power may fluctuate as a result of the weather, but those costs are passed through directly to customers.

The Empire District Electric System experiences peak loads in both the winter and summer seasons, due to heating and cooling loads associated with weather in its service territory. The Energy Service price for power may fluctuate as a result of the weather, but those costs are passed through directly to customers and as a result does not have a material financial impact.

(iii) Natural Gas Systems

The Regulated Services Group's primary demand for natural gas from its natural gas distribution systems is driven by the seasonal heating requirements of its residential, commercial and industrial customers. The colder the weather, the greater the demand for natural gas to heat homes and businesses. As such, the natural gas distribution systems' demand profiles typically peak in the winter months of January and February and decline in the summer months of July and August. Year to year variability also occurs depending on how cold the weather is in any particular year.

The Regulated Services Group attempts to mitigate the above noted fluctuations by seeking regulatory mechanisms during rate case proceedings. Certain jurisdictions have approved constructs to mitigate demand fluctuations. For example, at the Peach State Gas System, EnergyNorth Gas System and Midstates Gas Systems, a weather normalization adjustment is applied to customer bills that adjusts commodity rates to stabilize the revenues of the utility for changes in billing units attributable to weather patterns. Most regulatory jurisdictions in which the Regulated Services Group operates have approved mechanisms to mitigate gas demand fluctuations.

3.3 Corporate Development Activities

The Corporation undertakes development activities with a global reach to identify, develop and construct renewable power generating facilities, power transmission lines, water infrastructure assets and other complementary infrastructure projects, and to invest in electric, natural gas, water distribution and wastewater collection utility systems.

The Corporation has identified an approximately $9.2 billion development pipeline consisting of approximately $6.7 billion of investment in its Regulated Services Group and approximately $2.5 billion of investments in its Renewable Energy Group through the end of 2024.

3.3.1 Development of Renewable Energy Assets

The Renewable Energy Group works to identify, develop and construct new power generating facilities and transmission lines, as well as to identify and acquire existing projects that would be complementary and accretive to the Renewable Energy Group's existing portfolio. The Renewable Energy Group is committed to working proactively with all stakeholders including local communities. The Renewable Energy Group believes that future opportunities for power generation projects will continue to develop as new targets are set for renewable and other clean power generation projects.

The Renewable Energy Group has successfully advanced a number of projects and has been awarded or acquired a number of PPAs and/or long-term hedging arrangements. The projects identified are at various stages of development, and have advanced to a stage where the resolutions to major project uncertainties are probable, but not certain, and it is expected that the project will meet management's risk adjusted return expectations.

The Renewable Energy Group's five-year $2.5 billion development pipeline consists of investments in renewable generation projects in North America and indirect international investments. The following table represents the Renewable Energy Group's development and construction projects:

Project Name	Location	Anticipated Size (MW)
Projects in Construction		
Altavista Solar Project[1, 2]	Virginia	80
Great Bay II Solar Project	Maryland	45
Maverick Creek Wind Project[1]	Texas	490
Sugar Creek Wind Project[1]	Illinois	202
Val-Éo Wind Project[1]	Québec	24
Total Projects in Construction		**841**
Total Projects in Development		**600**
Total Projects in Construction and Development		**1,441**

1 The project is currently held in a joint venture, of which the Renewable Energy Group and a third party each own a 50% equity interest.

2 Power from the project will be sold, in part, to Facebook Operations, LLC, a wholly-owned subsidiary of Facebook, Inc., pursuant to a 12-year power purchase agreement.

3.3.2 Development of Regulated Services Assets

The Regulated Services Group's strategy is to grow its business organically and through acquisitions. The approximately five-year $6.7 billion Regulated Services asset pipeline consists of investments in organic rate base capital expenditures, capital expenditures related to improving the choice and efficiency of service provided to customers, pending acquisitions and initiatives focused on transition to green energy ("**Greening the Fleet**").

Organic rate base capital expenditures are primarily related to the maintenance and expansion of existing rate base assets, including: the construction of transmission and distribution main replacements, work on new and existing substation assets and initiatives relating to the safety and reliability of the electric and gas systems.

Capital expenditures related to improving quality and efficiency of service to the Corporation's customers include the implementation of new customer information systems, advanced metering systems and behind the meter solutions.

Pending acquisitions include Ascendant and New York American Water.

The Greening the Fleet initiatives consist primarily of the Mid-West Wind Development Project (described below) and other initiatives related to the transition to renewable energy generation at our existing regulated facilities, including transitioning the CalPeco Electric System to 100% renewable energy and, following the anticipated closing of the acquisition of Ascendant, reducing the reliance on diesel generation at BELCO by replacing it with a combination of renewable energy generation and storage.

(i) Mid-West Wind Development Project

In 2017, the Regulated Services Group presented a plan to the applicable public utility commissions for an investment in up to 600 MW of strategically located wind energy generation which is forecast to reduce energy costs for its customers. The plan consists of development of an approximately 300 MW wind project in southeastern Kansas, and two approximately 150 MW wind projects in southwestern Missouri.

On May 9, 2019, the APSC issued its order allowing the commencement of construction of the projects. In the fourth quarter of 2018, Empire applied to the MPSC for approval of certificates of convenience and necessity ("**CC&N**") for the projects. The Commission issued an order approving the CC&N application, effective June 29, 2019.

Liberty Utilities Co. has acquired an interest in the entities that own the two Missouri projects and, in partnership with a third-party developer, will continue development and construction of the two Missouri projects. A second third-party developer is developing the wind project in Kansas. Empire has entered into contracts to acquire the three wind projects upon completion.

Construction of two of the wind projects began in the fourth quarter of 2019 and construction of the third project began in the first quarter of 2020.

(ii) Wataynikaneyap Power Transmission Project

On January 17, 2019, the Regulated Services Group acquired from Fortis Inc. a 9.8% ownership interest in an electricity transmission project located in Northwestern Ontario (the "**Wataynikaneyap Power Transmission Project**") that is expected to connect 17 remote First Nation communities to the Ontario provincial electricity grid through the construction of approximately 1,800 km of transmission lines. In addition to providing participating First Nations communities ownership in the transmission line, the Wataynikaneyap Power Transmission Project is expected to result in socio-economic benefits for surrounding communities, reduce environmental risk, and lessen greenhouse gas emissions associated with diesel-fired generation currently used in that area.

In April 2019, the Ontario Energy Board approved the leave-to-construct application. Completion of construction financing and issuance of notice to proceed to the EPC contractor occurred in October 2019. The Wataynikaneyap Power Transmission Project is targeted to be complete by the end of 2023.

3.4 Principal Revenue Sources

APUC owns, directly or indirectly, interests in renewable generation facilities, thermal generation facilities, electricity distribution utilities, natural gas and propane distribution utilities, and water distribution and wastewater utilities.

The following provides a breakdown of the Corporation's total revenue by percentage for the years ended December 31, 2018 and December 31, 2019:

	% Total Revenue	
	December 31, 2018	**December 31, 2019**
Non-regulated energy sales	14.3%	15.2%
Utility electricity sales & distribution	50.5%	48.3%
Utility natural gas sales & distribution	26.1%	27.0%
Utility water distribution and wastewater treatment sales & distribution	7.8%	8.0%
Other revenue[1]	1.3%	1.5%

1 Other revenue includes gas transportation and RECs.

The purchase of electricity and natural gas by the Corporation's electricity distribution and natural gas distribution systems is a significant revenue driver and component of operating expenses, but these costs are effectively passed through to its customers. As a result, the Corporation uses Net Energy Sales for the Renewable Energy Group (see "Non-GAAP Financial Measures") and Net Utility Sales for the Regulated Services Group (see "Non-GAAP Financial Measures") as a more appropriate measure of the results. Adjusting for the impact of these commodity costs, the following provides a breakdown of the Corporation's Net Energy Sales and Net Utility Sales by percentage for the years ended December 31, 2018 and December 31, 2019:

	% Net Energy Sales/Net Utility Sales	
	December 31, 2018	**December 31, 2019**
Non-regulated energy sales	17.9%	19.4%
Utility electricity sales & distribution	48.7%	45.4%
Utility natural gas sales & distribution	21.3%	22.7%
Utility water distribution and wastewater treatment sales & distribution	10.3%	10.4%
Other revenue[1]	1.8%	2.1%

1 Other revenue includes gas transportation and RECs.

For the Renewable Energy Group, the following provides a breakdown of revenue by percentage for the years ended December 31, 2018 and December 31, 2019:

	% Revenue	
	December 31, 2018	**December 31, 2019**
Wind generation	54.0%	59.4%
Solar generation	7.0%	7.2%
Hydroelectric generation	17.2%	16.2%
Thermal generation	17.0%	12.8%
Other revenue[1]	4.8%	4.4%

1 Other revenue includes RECs.

For the Regulated Services Group, the following provides a breakdown of revenue by percentage for the years ended December 31, 2018 and December 31, 2019:

	% Revenue	
	December 31, 2018	December 31, 2019
Utility electricity sales & distribution	59.4%	57.4%
Utility natural gas sales & distribution	30.6%	32.0%
Utility water distribution and wastewater treatment sales & distribution	9.2%	9.5%
Other revenue[1]	0.8%	1.1%

1 Other revenue includes gas transportation.

3.5 Environmental Protection

The Corporation's businesses encompass operations which require adherence to environmental standards imposed by regulatory bodies through licenses, permits, standards, policies and legislation. Failure to operate such businesses in strict compliance with these regulatory standards may expose them to citations, claims, clean-up costs, penalties, and loss of operating licenses and permits.

The Corporation has an environmental management program including environmental policies and procedures that involve long-term environmental monitoring programs, reporting, government liaison and the development and implementation of emergency action plans as related to environmental matters, and environmental and compliance departments with responsibility for monitoring the Corporation and its subsidiaries' operations.

Environmental protection requirements did not have a significant financial or operational effect on the Corporation's capital expenditures, earnings and competitive position for the twelve months ended December 31, 2019. Moreover, other regimes that provide incentives and credits for generation of renewable energy and for carbon offsets, such as those described elsewhere in this AIF, are expected to increase the earnings and benefit the competitive position of the Corporation.

The Corporation faces a number of environmental risks that are normal aspects of operating within the renewable power generation, thermal power generation and utilities business segments which have the potential to become environmental liabilities (see "Enterprise Risk Factors – Risks Relating to Operations").

3.6 Employees

The Corporation's executive management group consists of ten individuals. As at December 31, 2019, the Corporation employed a total of 2,469 people.

3.7 Foreign Operations

For the twelve months ended December 31, 2019, 98.65% of the revenue of the Regulated Services Group and approximately 66.19% of the revenue of the Renewable Energy Group was generated from operations located in the United States.

3.8 Economic Dependence

The Corporation does not believe it is substantially dependent on any single contractual agreement or set of related agreements.

3.9 Social and Environmental Policies and Commitment to Sustainability

The Corporation is committed to advancing a sustainable energy and water future. The Corporation aims to be a top quartile global utility, known for its dedication to safety and reliability, customer experience, employee engagement, community inclusion, environmental and social responsibility and financial performance.

Sustainability is often defined by a company's philosophy to operate in an economically, socially and environmentally sustainable manner, while recognizing the interests of its stakeholders. The Corporation believes this philosophy will contribute to a sustainable future for its investors, communities, environment, customers, employees, governments and business partners. The Corporation has formal policies and procedures that support its commitment to sustainability.

Oversight of Sustainability

The mandate of the Board states that in providing oversight of the corporate strategy, the Board will "…review the [strategy] plans in light of management's assessment of emerging trends, opportunities, the competitive environment, risk issues and significant business practices." The Board has determined that the mandate of its Corporate Governance Committee includes oversight of the ongoing development and progress of Corporations' sustainability plan and initiatives, and periodic reporting to the Board on progress related to the plan. The oversight of the Board is an essential step to ensure that sustainability performance is explicitly integrated into APUC's corporate strategy.

Accountability for developing and managing the Corporation's sustainability plans and initiatives has been assigned to APUC's Chief Governance Officer and Corporate Secretary who leads the Corporation's sustainability team. The mandate of the sustainability team is to ensure that the opportunities and risks relating to sustainability (environmental, social, and governance) as identified by the Corporation are considered and addressed as core components of the strategy and business processes of the organization, and to implement practices and programs throughout the Corporation that support the achievement of its mission.

In September 2018, the Corporation adopted its first Corporate Sustainability Policy. The Sustainability Policy is aligned with the United Nations' Sustainable Development Goals (SDGs), namely Gender Equality (SDG5), Clean Water and Sanitation (SDG6), Affordable and Clean Energy (SDG7), Decent Work and Economic Growth (SDG8), Sustainable Cities and Communities (SDG11) and Climate Action (SDG13). By embedding these tenets into its decision making, the Corporation is committed to building and operating its business such that it makes a positive and durable contribution to a sustainable energy and water future.

Social Policies

The Corporation's Code of Business Conduct and Ethics is a key component of the Corporation's sustainability plan. All directors, officers, employees, agents and contractors are required to read the Code of Business Conduct and Ethics and apply the code to their work. Employees are required to complete an annual online test which confirms their compliance with and understanding of the Code of Business Conduct and Ethics.

The Corporation's sustainability efforts incorporate local spending, local hiring and operational efficiency. The Corporation's commitment to people is demonstrated through its employee training, learning and development programs, organizational improvements, emergency management programs and community involvement. Policies in place that support the Corporation's commitment to sustainability include its Diversity Policy, Ethic Reporting Policy and Supplier Code of Conduct.

Environmental, Health and Safety

The Corporation's businesses have safety and environmental compliance policies in place. These policies have been communicated with employees and have been incorporated into their respective Safety Mission Statements and employee manuals. The Corporation's Environmental and Health and Safety Groups are responsible for developing environmental and safety policies, developing and facilitating environmental and safety training, conducting internal audits of environmental and safety performance, and arranging for third party environmental and safety audits. The Corporation is in the process of implementing an environmental management system designed to provide for the continuous measurement, evaluation and improvement of the Corporation's management of its environmental compliance, risks and performance. The Corporation has environmental programs in place that promote energy efficiency and responsible water usage, help facilitate habitat conservation to minimize impact, monitor greenhouse gas emissions and promote waste reduction and spill prevention.

Sustainability Report

In November 2019, the Corporation released its 2019 Sustainability Report, which sets out its commitment to sustaining energy and water by communicating the Corporation's strategies, initiatives, and goals relating to the three elements of sustainability: the environment; the social matters important to the Corporation's strategy and the Corporation's relationship with its key stakeholder groups including employees, customers and the communities in which it operates and serves; and the governance framework under which the Corporation operates.

3.10 Credit Ratings

The following chart shows credit ratings issued to the Corporation and currently in effect.[1]

	S&P	DBRS	Fitch	Moody's
APUC - Issuer rating	BBB	BBB	BBB	-
APUC - Preferred Shares	P-3 (high)	Pfd-3	-	-
APUC - 2018 Subordinated Notes	BB+	-	BB+	-
APUC - 2019 Subordinated Notes	BB+	-	BB+	-
APCo - Issuer rating	BBB	BBB	BBB	-
APCo - Senior unsecured debt	BBB	BBB	-	-
Liberty Utilities Canada - Issuer Rating	-	BBB	-	-
Liberty Utilities Canada - Senior unsecured debt	-	BBB	-	-
Liberty Utilities Co. - Issuer rating	BBB	-	BBB	-
Liberty Utilities Co. - Commercial Paper	A-2	-	F2	-
Liberty Utilities Finance GP1 - Issuer rating[2]	-	BBB (high)	-	-
Liberty Utilities Finance GP1 - Senior unsecured notes	-	BBB (high)	BBB+	-
Empire - Issuer rating	BBB	-	-	Baa1
Empire - First mortgage bonds	A-	-	-	A2
Empire - Senior unsecured debt	BBB	-	-	Baa1
Empire - Commercial paper	A-2	-	-	P-2

1 Credit ratings are intended to provide investors with an independent measure of the credit quality of an issue of securities. Credit ratings are not a recommendation to buy, sell or hold securities of APUC or any of its subsidiaries and do not comment as to market price or suitability for a particular investor. There can be no assurance that a rating will remain in effect for any given period of time or that the rating will not be revised or withdrawn at any time by the rating agency.

2 Issued by Liberty Utilities Finance GP1 and guaranteed by Liberty Utilities Co.

S&P

S&P rates long-term debt instruments and issuers with ratings ranging from "AAA", which represents an extremely strong capacity of an obligor to meet its financial commitment, to "D", which means that, in the case of an issue rating, that the issuer is in default or in breach of an imputed promise, and in the case of an issuer rating, that there is a general default and the obligor will fail to pay all or substantially all of its obligations as they become due. A rating of "A" by S&P denotes an obligation somewhat more susceptible to the adverse effects of changes in circumstances and economic conditions than obligations in higher-rated categories; however, the obligor's capacity to meet its financial commitments on the obligation is still strong. A rating of "BBB" by S&P denotes an obligor having adequate capacity to meet its financial commitments; however, adverse economic conditions or changing circumstances are more likely to weaken the obligor's capacity to meet its financial commitments. A rating of "BB" by S&P is included amongst a range of ratings determined to have significant speculative characteristics. An obligation rated "BB" is less vulnerable to nonpayment than other speculative issues; however, it faces major ongoing uncertainties or exposure to adverse business, financial, or economic conditions that could lead to the obligor having inadequate capacity to meet its financial commitments. S&P ratings from "AA" to "CCC" may be modified by the addition of a plus "+" or minus "-" sign to show relative standing within the major rating categories. The absence of either a plus "+" or minus "-" sign indicates that the rating is in the middle of the category.

S&P rates short-term debt instruments and issuers with ratings ranging from "A-1", which represents an extremely strong capacity of an obligor to meet its financial commitment, to "D", which means that the issuer is in default or in breach of an imputed promise. A rating of "A-2" by S&P denotes an obligation somewhat more susceptible to the adverse effects of changes in circumstances and economic conditions than obligations in higher-rated categories; however, the obligor's capacity to meet its financial commitments on the obligation is still satisfactory.

S&P's Canadian preferred share rating scale serves the Canadian financial markets by expressing preferred share ratings in terms of rating symbols that have been actively used in the Canadian market over a number of years. There is a direct correspondence between the specific ratings assigned on the Canadian preferred share scale and the various rating levels on S&P's global preferred share rating scale. S&P's Canadian preferred share rating scale ranges from "P-1", which represents a very strong capacity of an obligor to meet its financial commitments, to "P-5", which represents an obligation vulnerable to nonpayment and which is dependent upon favorable business, financial and economic conditions for the obligor to meet its financial commitments. A preferred share rating of "P-3 (high)" is equivalent to a rating of "BB+" on S&P's global scale (which is discussed above). Ratings from "P-1" to "P-5" may be modified by "high" and "low" grades which indicate relative standing within the major rating categories.

DBRS

DBRS rates debt instruments and issuers with ratings ranging from "AAA", which represents debt instruments and issuers of the highest credit quality, to "D", which represents debt instruments for which an issuer has filed under any applicable bankruptcy, insolvency or winding up statute or for which there is a failure to satisfy an obligation after the exhaustion of grace periods. A rating of "BBB" by DBRS denotes an obligor having adequate credit quality; the capacity for the payment of financial obligations is considered acceptable although it may be vulnerable to future events. All rating categories other than "AAA" and "D" also contain subcategories "(high)" and "(low)". The absence of either a "(high)" or "(low)" designation indicates that the rating is in the middle of the category.

The DBRS preferred share rating scale ranges from "Pfd-1", which represents a superior credit quality, supported by entities with strong earnings and balance sheet characteristics, to "D", which represents that an issuer has filed under any applicable bankruptcy, insolvency or winding up statute or is in default per the legal documents. Preferred shares rated "Pfd-3" are of adequate credit quality. While protection of dividends and principal is still considered acceptable, the issuing entity is more susceptible to adverse changes in financial and economic conditions, and there may be other adverse conditions present which detract from debt protection. "High" or "low" grades are used to indicate the relative standing within a rating category. The absence of either a "high" or "low" designation indicates the rating is in the middle of the category.

Fitch

Fitch rates long-term debt instruments and issuers with ratings ranging from "AAA", which represents the highest credit quality and denotes the lowest expectation of default risk, to, in the case of rating for the debt instruments themselves, "C" which indicates exceptionally high levels of credit risk, or, in the case of issuer ratings, "D", which indicates an issuer that in Fitch's opinion has entered into bankruptcy filings, administration, receivership, liquidation or other formal winding-up procedure or that has otherwise ceased business. A rating of "BBB" by Fitch indicates that expectations of default risk are currently low. The capacity for payment of financial commitments is considered adequate, but adverse business or economic conditions are more likely to impair this capacity. A rating of "BB" by Fitch indicates an elevated vulnerability to credit risk, particularly in the event of adverse changes in business or economic conditions over time; however, business or financial alternatives may be available to allow financial commitments to be met. Ratings from "AA" to "CCC" may be modified by the addition of a plus "+" or minus "-" sign to show relative standing within the major rating categories. The absence of either a plus "+" or minus "-" sign indicates that the rating is in the middle of the category.

Fitch rates short-term debt instruments and issuers with ratings ranging from "F1", which represents the highest credit quality and denotes the lowest expectation of default risk, to "D", which indicates an issuer default or the default of a short-term obligation. A rating of "F2" by Fitch indicates that expectations of default risk are currently low. There is considered to be a good capacity for payment of financial commitments. Ratings of "F1" may be modified by the addition of a plus "+" to denote any exceptionally strong credit feature.

Moody's

Moody's rates long-term debt instruments and issuers with ratings ranging from "Aaa", which represents obligations judged to be of the highest quality, subject to the lowest level of credit risk, to "C", which represents an obligation typically in default, with little prospect for recovery of principal or interest. A rating of "A" by Moody's denotes obligations judged to be upper-medium grade and subject to low credit risk, while a rating of "Baa" by Moody's denotes obligations judged to be medium-grade and subject to moderate credit risk and as such may possess certain speculative characteristics. A Moody's rating of "Aa" through "Caa" may be modified by the addition of numerical modifiers 1, 2 and 3 to show relative standing within the major rating categories. The modifier 1 indicates that the obligation ranks in the higher end of its generic rating category; the modifier 2 indicates a mid-range ranking; and the modifier 3 indicates a ranking in the lower end of that generic rating category.

Short-term obligations and issuers thereof may carry a rating ranging from Prime-1 or “P-1”, which represents an issuer’s superior ability to repay short-term debt obligations, to “Prime-3” or “P-3”, which represents an issuer’s acceptable ability to repay short-term obligations. Issuers may also be rated “Not Prime” or “NP”, which represents that an issuer does not fall within any of the Prime rating categories.

The Corporation has made, or will make, payments to each of S&P, DBRS, Fitch and Moody’s in connection with the assignment of ratings to both the Corporation and its securities. In addition, the Corporation has made customary payments in respect of certain subscription services provided to the Corporation by S&P and Fitch during the last two years.

4. ENTERPRISE RISK FACTORS

The Corporation is subject to a number of risks and uncertainties, certain of which are described in more detail below. The actual effect of any event on the Corporation’s business could be materially different from what is anticipated or described below. The description of risks below does not include all possible risks. See APUC’s MD&A for the year ended December 31, 2019 for additional risks which it faces.

Led by the Chief Compliance and Risk Officer, the Corporation has an established enterprise risk management, or ERM, framework. The Corporation’s ERM framework follows the guidance of ISO 31000 and the COSO Enterprise Risk Management – Integrated Framework. The Corporation’s ERM framework is intended to systematically identify, assess and mitigate the key strategic, operational, financial and compliance risks that may impact the achievement of the Corporation’s current objectives, as well as those inherent to strategic alternatives available to the Corporation. The Corporation’s Board-approved ERM policy details the Corporation’s risk management processes, risk appetite and risk governance structure.

As part of the risk management process, risk registers have been developed across the organization through ongoing risk identification and risk assessment exercises facilitated by the Corporation’s internal ERM team. Key risks and associated mitigation strategies are reviewed by the executive-level Enterprise Risk Management Council and are presented to the Board’s Risk Committee periodically.

Risks are evaluated consistently across the Corporation using a standardized risk scoring matrix to assess impact and likelihood. Financial, reputational and safety implications are among those considered when determining the impact of a potential risk. Risk treatment priorities are established based upon these risk assessments and incorporated into the development of the Corporation’s strategic and business plans.

4.1 Risk Factors Relating to Operations

The Corporation’s operations involve numerous risks which, if they materialize, could disrupt or adversely affect its business, results of operations, financial position and cash flows.

The Corporation’s ability to safely and reliably operate, maintain, construct and decommission (as applicable) its power generation facilities, utility systems and other assets involve a variety of risks customary to the power and utilities sector, many of which are beyond the Corporation’s control, including those that arise from:

- severe weather conditions and natural disasters;
- global climate change;
- environmental contamination/wildlife impacts;
- casualty or other significant events such as fires, explosions, security breaches or drinking water contamination;
- commodity supply and transmission constraints or interruptions;
- workplace and public safety events;
- infectious diseases, pandemics and similar public health threats, such as the 2019 Novel Coronavirus;
- loss of key personnel;
- labour disputes;
- employee performance/workforce effectiveness;
- improper or erroneous acts of employees;
- demand (including seasonality);
- loss of key customers;

- reduction in the price received for goods/services;
- reliance on transmission systems and facilities operated by third parties;
- land use rights/access;
- critical equipment breakdown or failure;
- supply chain disruptions;
- lower-than-expected levels of efficiency or operational performance;
- acts by third parties, including cyber-attacks, criminal acts, vandalism, war and acts of terrorism;
- projects with a limited operating history;
- opposition by external stakeholders, including local groups, communities and landowners;
- commodity price fluctuations;
- lower prices for alternative fuel sources;
- obligations to serve; and
- the Corporation's reliance on subsidiaries.

These and other operating events and conditions could result in service and operational disruptions and may reduce the Corporation's revenues, increase costs or both, and may materially affect its business, results of operations, financial position, valuation and cash flows, particularly if a situation is not resolved in a timely manner or the financial impacts of restoration are not alleviated through insurance policies or regulated rate recovery.

The Corporation's generation, distribution and transmission utility assets may be negatively impacted by changes in general economic, credit, social and market conditions.

The Corporation's generation, distribution and transmission utility assets are affected by energy demand in the jurisdictions in which they operate. That demand may change as a result of fluctuations in general economic conditions, energy prices, employment levels, personal disposable income and housing starts. Significantly reduced energy demand in the Corporation's service territories could reduce capital spending forecasts, and specifically capital spending related to new customer growth. A reduction in capital spending could, in turn, affect the Corporation's rate base and earnings growth. A severe prolonged downturn in economic conditions may have an adverse effect on the Corporation's results of operations, financial condition and cash flows despite regulatory measures, where applicable, available to compensate for reduced demand. In addition, an extended decline in economic conditions could make it more difficult for customers to pay for the utility services they consume, thereby affecting the aging and collection of the utilities' trade receivables.

Energy conservation, energy efficiency, distributed generation, community choice aggregation and other factors that reduce energy demand could adversely affect the Corporation's business, financial condition and results of operations.

The emergence of initiatives designed to reduce greenhouse gas emissions and control or limit the effects of climate change has increased the incentive to increase energy efficiency and reduce energy consumption. In addition, significant technological advancements are taking place in the electric industry, including advancements related to self-generation and distributed energy technologies such as fuel cells, micro turbines, wind turbines and solar panels. Adoption of these technologies may increase as a result of government subsidies, improving economics and changing customer preferences.

Increased adoption of these practices, requirements and technologies could reduce demand for utility-scale electricity generation, which may adversely affect market prices at which the Renewable Energy Group can sell wholesale electric power.

Increased adoption of these practices may decrease the pool of customers from whom fixed costs would be recovered. If the Regulated Services Group were unable to adjust distribution rates to reflect the reduced energy demand, the Corporation's business, financial condition and results of operations could be adversely affected.

The Corporation and its facilities, operations and personnel are exposed to the effects of severe weather, natural disasters, diseases, and other catastrophic and force majeure events beyond the Corporation's control, as well as those that may be caused by climate change, and such events could result in a material adverse effect on the Corporation.

The Corporation's facilities and operations are exposed to potential interruption and damage, and partial or full loss, resulting from environmental disasters, other seismic activity, equipment failures and the like. There can be no assurance that in the event of an earthquake, hurricane, tornado, fire, flood, ice storm, tsunami, typhoon, terrorist attack, cyber-attack, act of war or other natural, manmade or technical catastrophe, all or some parts of the Corporation's generation facilities and infrastructure systems will not be disrupted. The occurrence of a significant event which disrupts the ability of the

Corporation's power generation assets to produce or sell power for an extended period, including events which preclude existing customers under PPAs from purchasing electricity, could have a material negative impact on the Corporation's business. The Corporation's assets could be exposed to effects of severe weather conditions, natural and man-made disasters and potentially other catastrophic events. The occurrence of such an event may not release the Corporation from performing its obligations pursuant to PPAs or other agreements with third parties. In addition, certain of the Corporation's utilities operate in remote and mountainous terrain, where the Corporation's facilities are at increased risk of loss or damage from fires, floods, washouts, landslides, earthquakes, avalanches and other acts of nature.

An outbreak of infectious disease, a pandemic or a similar public health threat, such as the 2019 Novel Coronavirus outbreak, or a fear of any of the foregoing, could adversely impact the Corporation by causing operating, supply chain and project development delays and disruptions, labour shortages and shutdowns (including as a result of government regulation and prevention measures), and increased costs to the Corporation.

Climate change is predicted to lead to increased frequency and intensity of weather events and related impacts such as storms, wildfires, flooding and storm surge. Extreme weather events create a risk of physical damage to the Corporation's assets. High winds can damage structures, and cause widespread damage to transmission and distribution infrastructure. Increased frequency and severity of weather events increases the likelihood that the duration of power outages and fuel supply disruptions could increase. Increased intensity of flooding could adversely affect the operations of the Corporation's hydroelectric generating facilities.

The potential impacts of climate change, such as rising sea levels and larger storm surges from more intense hurricanes, can combine to produce greater damage to coastal located generation and other facilities.

Although assets have been constructed and are operated and maintained to minimize such damage, there can be no assurance these measures will fully mitigate the risk.

Climate change is also characterized by increases in global air temperatures. Increased air temperatures may bring increased frequency and severity of wildfires, including within the Corporation's service territories in California and the southern United States. Increased air temperatures could also result in decreased efficiencies over time of both generation and transmission facilities.

If it is found to be responsible for such a fire, the Corporation could suffer costs, losses and damages, all or some of which may not be recoverable through insurance, legal, regulatory cost recovery or other processes and could materially affect the Corporation's business, results of operations and cash flows, including its reputation with customers, regulators, governments and financial markets. Resulting costs could include fire suppression costs, regeneration, timber value, asset replacement costs, increased insurance costs and costs arising from damages and losses incurred by third parties.

In addition, customers' energy needs vary significantly in response to weather conditions, primarily temperature and humidity. For residential customers, heating and cooling represent their largest energy use. To the extent weather conditions are affected by climate change, customers' energy use could increase or decrease depending on the duration and magnitude of the changes, which may adversely affect the Corporation's business, results of operations and cash flows.

The Corporation and its subsidiaries face a number of environmental risks which have the potential to result in significant environmental liabilities.

The Corporation and its subsidiaries face a number of environmental risks that are normal aspects of operating within the power generation and utilities business segments, which have the potential to result in harm to the environment, including wildlife, resulting in significant environmental liabilities and reputational impact. Certain environmental risks associated with the Corporation's operations include uncontrolled natural gas or contaminant releases (or releases above the permitted limits), generation of hazardous materials, failure to maintain compliance with obligations under permits and licenses (such as continuous emissions monitoring, periodic reporting/source testing, and general performance/operating conditions), acquired legacy environmental liabilities, operations adjustments or liability, and related financial impacts, resulting from wildlife mortality, emissions, including noise, and dam safety.

In addition, the Corporation's operating subsidiaries generate certain hazardous wastes, which must be managed in accordance with various federal, state and local environmental laws. Under federal and state laws, potential liability for historic contamination of property may be imposed on responsible parties jointly and severally, without fault, even if the activities were lawful when they occurred.

Harming of protected species can result in curtailment of wind project operations as well as delays in construction project schedules and could have a material adverse effect on the Corporation's business, financial condition, results of operation and cash flows.

The operation of energy and transmission projects can adversely affect endangered, threatened or otherwise protected animal species under federal, state or provincial statutes, laws, rules and regulations. Wind projects and transmission and distribution lines involve a risk that protected flying species, such as birds and bats, will be harmed due to collision. Energy generation and transmission facilities can result in impacts to protected wildlife, including death caused by collision, electrocution and poisoning. Violations of wildlife protection laws in certain jurisdictions, including violations of certain laws protecting migratory birds and endangered species, may result in civil or criminal penalties, or cessation of certain operations or projects, and could adversely affect the Corporation's financial condition, results of operations and cash flows.

Security breaches, criminal activity, theft, terrorist attacks, cyber-attacks and other threats or incidents relating to the Corporation's information security could directly or indirectly interfere with the Corporation's operations, could expose the Corporation or its customers or employees to risk of loss, and could expose the Corporation to liability, regulatory penalties, reputational damage and other harm to its business.

The Corporation relies upon information technology networks, systems and devices to process, transmit and store electronic information, and to manage and support a variety of business processes and activities. The Corporation also uses information technology systems to record, process and summarize financial information and results of operations for internal reporting purposes and to comply with financial reporting, legal and tax requirements. The Corporation's technology networks, systems and devices collect and store sensitive data, including system operating information, proprietary business information belonging to the Corporation and third parties, as well as personal information belonging to the Corporation's customers and employees.

The Corporation's or its third-party vendor's information systems and information technology networks, devices and infrastructure may be vulnerable to damage, disruptions or shutdowns due to attacks by hackers or breaches due to employee error or malfeasance, disruptions during software or hardware upgrades, telecommunication failures, theft, natural disasters or other similar events. In addition, certain sensitive information and data may be stored by the Corporation in physical files and records on its premises or transmitted to the Corporation verbally, subjecting such information and data to a risk of loss, theft and misuse. The occurrence of any of these events could impact the reliability of the Corporation's power generation facilities and utility distribution systems; could expose the Corporation, its customers or its employees to a risk of loss or misuse of information; and could result in legal claims or proceedings, liability or regulatory penalties against the Corporation, damage the Corporation's reputation or otherwise harm the Corporation's business.

The Corporation cannot accurately assess the probability that a security breach may occur or accurately quantify the potential impact of such an event. The Corporation can provide no assurance that it will be able to identify and remedy all cybersecurity, physical security or system vulnerabilities or that unauthorized access or errors will be identified and remedied.

The loss of key personnel, the inability to hire and retain qualified employees, and labour disruptions could adversely affect the Corporation's business, financial position and results of operations.

The Corporation's operations depend on the continued efforts of its employees. Hiring and retaining key employees and maintaining the ability to attract new employees are important to the Corporation's operational and financial performance. The Corporation cannot guarantee that any member of its management or any one of its key employees will continue to serve in any capacity for any particular period of time or that any leadership transitions will be successful.

Certain events or conditions, such as an aging workforce, epidemic, pandemic or similar public health emergency (including the 2019 Novel Coronavirus), mismatch of skill set or complement to future needs, or unavailability of contract resources may lead to operating challenges, labour disruption and increased costs. The challenges the Corporation might face as a result of such risks include a lack of resources, losses to its knowledge base and the time required to develop new workers' skills. In any such case, costs, including costs for contractors to replace employees, productivity costs and safety costs may rise. If the Corporation is unable to successfully attract and retain an appropriately qualified workforce, its financial position or results of operations could be negatively affected.

The maintenance of a productive and efficient labour environment without disruptions cannot be assured. In the event of a strike, work stoppage or other form of labour disruption, the Corporation would be responsible for procuring replacement labour and could experience disruptions in its operations and incur additional expense.

The Corporation's revenues and results of operations are affected by seasonal fluctuations and year to year variability in weather conditions and natural resource availability.

The Corporation is subject to risks associated with seasonal fluctuations and year to year variability in weather conditions and natural resource availability, which affect the quantity of electric power generated and sold by the Renewable Energy Group, the availability of water to be distributed by the Regulated Services Group and the demand for the utility services of the Regulated Services Group.

The Regulated Services Group's water distribution operations depend on an adequate supply of water to meet present and future demands of customers. Drought conditions could interfere with sources of water supply used by the utilities and affect their ability to supply water in sufficient quantities to existing and future customers. An interruption in the water supply could have an adverse effect on the results of operations of these utilities.

Demand for water, electricity and natural gas from the Regulated Services Group's utility distribution systems is affected by weather conditions and temperature. Demand for water may decrease if there is above normal rainfall or rainfall is more frequent than normal, or if government restrictions are imposed on water usage during drought conditions. Demand for electricity and natural gas are also subject to significant seasonal variation, year-to-year variations and changes in weather patterns.

Please see "Description of the Business – Renewable Energy Group – Cycles and Seasonality" and "Description of the Business – Regulated Services Group – Cycles and Seasonality" for a description and discussion of these risks.

The Corporation historically has entered, and may in the future, enter into long-term PPAs and derivative contracts to reduce the risk of fluctuations in electricity prices, which contracts could give rise to performance and financial risks and could result in significant costs to the Corporation.

The Renewable Energy Group sells a significant portion of the energy (and renewable energy credits) it generates under long-term PPAs. The Renewable Energy Group also enters into financial or physical power hedges to reduce the risk from fluctuations in market price. For instance, several of the Renewable Energy Group's wind energy production facilities are subject to long-term hourly energy price hedges for a portion of their expected energy production. The Corporation may incur significant costs in establishing or terminating hedging arrangements or may be unable to benefit from favourable changes in market price as a result of these hedges.

In addition, the Corporation may not be able to generate power in the amounts or at the times required by the applicable hedge contract, due to the variable nature of the natural resource (for renewable power generation) or due to transmission grid curtailments, mechanical failures or other reasons. Because of this risk, the Corporation typically does not hedge the full expected production of a particular facility, which leaves a portion of expected production subject to market price risk. In addition, production shortfalls may force the Renewable Energy Group to purchase power in the merchant market at prevailing rates to settle against the applicable hedge contract. Such factors could materially and adversely affect the Corporation's results of operations and cash flows, depending on both the amount of shortfall and the market price of electricity at the time of the shortfall.

Changes in technology and regulatory policies may lower the value of electric utility facilities.

The Corporation primarily generates electricity at large central facilities and delivers that electricity to customers using its transmission and distribution facilities. This method results in economies of scale and generally lower costs than newer technologies, such as fuel cells and microturbines, and distributed generation using either new or existing technology. Other technologies, such as light emitting diodes (LEDs), increase the efficiency of electricity and, as a result, lower the demand for it. Changes in regulatory policies and advances in batteries or energy storage, wind turbines and photovoltaic solar cells are reducing costs of new technology to levels that are making them competitive with some central station electricity production and delivery. The ability to maintain relatively low-cost, efficient and reliable operations, to establish fair regulatory mechanisms and to provide cost-effective programs and services to customers are significant determinants of the Corporation's competitiveness. Further, in the event that alternative generation resources are mandated, subsidized or encouraged through climate legislation or regulation or otherwise are economically competitive and added to the available generation supply, such resources could displace a higher marginal cost central generating plant, which could reduce the price at which market participants sell their electricity. This occurrence could then reduce the market price at which all generators in that region would be able to sell their output and could adversely affect the Corporation's financial condition, results of operations and cash flows, which could also result in an impairment of certain long-lived assets.

The Renewable Energy Group's 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.

A substantial portion of the Renewable Energy Group's power generation facilities depend on electric transmission systems and related facilities owned and operated by third parties to deliver the electricity the Renewable Energy Group generates to delivery points where ownership changes and the Corporation 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 Renewable Energy Group's power generation facilities are physically disconnected from the power grid, or their production curtailed, for short periods of time. Most of the Corporation's electricity sales contracts do not provide for payments to be made if electricity is not delivered.

The power generation facilities of the Renewable Energy Group may also be subject to changes in regulations governing the cost and characteristics of use of the transmission and distribution systems to which its power generation facilities are connected. In the future, these power generation facilities may not be able to secure access to 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. Any such increased costs and delays could delay the commercial operation dates of Renewable Energy Group's new projects and negatively impact the Corporation's revenues and financial condition.

The Corporation does not own all of the land on which its projects are located and its use and enjoyment of real property rights for its projects may be adversely affected by the rights of lienholders and leaseholders that are superior to those of the grantors of those real property rights to the Corporation's subsidiaries' projects, which could have a material adverse effect on its business, results of operations, financial condition and cash flows.

The Corporation does not own all of the land on which its projects are located. Such projects generally are, and future projects may be, located on land occupied under long-term easements, leases and rights of way. The ownership interests in the land subject to these easements, leases and rights of way may be subject to mortgages securing loans or other liens and other easements, lease rights and rights of way of third parties that were created previously. As a result, some of the rights under such easements, leases or rights of way held by the Corporation may be subject to the rights of these third parties, and the rights of the Corporation to use the land on which its projects are or will be located and its rights to such easements, leases and rights of way could be lost or curtailed. Any such loss or curtailment of the rights of the Corporation to use the land on which its projects are or will be located could have a material adverse effect on its business, results of operations, financial condition and cash flows.

The Corporation may experience critical equipment breakdown or failure, which could have a material adverse effect on the Corporation's financial condition, results of operations, liquidity, reputation and ability to make distributions.

The Corporation's facilities are subject to the risk of critical equipment breakdown or failure and lower-than-expected levels of efficiency or operational performance due to the deterioration of assets from use or age, latent defect and design or operator error, among other things. These and other operating events and conditions could result in service disruptions and, to the extent that a facility's equipment requires longer than forecasted down times for maintenance and repair, or suffers disruptions of power generation, distribution or transmission for other reasons, the Corporation's business, operating results, financial condition or prospects could be adversely affected. In addition, a portion of the Corporation's infrastructure is located in remote areas, which may make access to perform maintenance and repairs difficult if such assets become damaged.

Disruption in the Corporation's supply chain may have a material adverse effect on the Corporation's business, results of operation, financial condition and cash flows.

The Corporation's ability to operate effectively is in part dependent upon timely access to equipment, materials and service suppliers. Loss of key equipment, materials and service suppliers and the reputational and financial risk exposures of key vendors could affect the Corporation's operations and execution and profitability of capital projects. In February 2020, the Corporation received force majeure notices from certain of its suppliers related to the 2019 Novel Coronavirus outbreak. The notices relate to wind energy projects from both the Regulated Services Group and the Renewable Energy Group and a solar project from the Renewable Energy Group. While the exact impacts of the 2019 Novel Coronavirus outbreak on the Corporation and its projects remain unknown, manufacturing and delivery delays caused by the 2019 Novel Coronavirus could adversely affect its projects, including (a) causing one or more projects scheduled for completion in 2020 to not be placed in service until 2021 or (b) adversely impacting the availability of tax equity or other financing. The Corporation is working with its suppliers, contractors and advisors in an effort to mitigate the impacts on its projects, but there can be no assurance that such efforts will be successful.

Terrorist attacks and cyber-attacks, and the threat of terrorist attacks and cyber-attacks, have resulted in increased costs to the business of the Corporation. Continued hostilities or sustained military campaigns may adversely impact the Corporation's consolidated financial position, results of operations and cash flows.

The long-term impact of terrorist attacks and cyber-attacks and the magnitude of the threat of future terrorist attacks and cyber-attacks on the electric utility and natural gas midstream industry in general, and on the Corporation in particular, cannot be known. Increased security measures taken by the Corporation as a precaution against possible terrorist attacks and cyber-attacks have resulted in increased costs to the business of the Corporation. Uncertainty surrounding continued hostilities or sustained military campaigns may affect operations of the Corporation in unpredictable ways, including disruptions of supplies and markets for products of the Corporation, and the possibility that the Corporation's infrastructure facilities could be direct targets of, or indirect casualties of, an act of terror. The Corporation cannot predict the impact that a terrorist attack or a cyber-attack may have on the energy industry in general. The Corporation's facilities could be direct targets or indirect casualties of such attacks. The effects of such attacks could include disruption to the Corporation's generation, transmission and distribution systems or to the electrical grid in general, and could result in a decline in the general economy and have a material adverse effect on the Corporation.

The Corporation's portfolio includes development and constructions projects, as well as recently completed projects that have a limited operating history. Such projects may not perform as expected.

The Corporation's portfolio includes development and constructions projects, as well as recently completed projects that have recently commenced operations and therefore have a limited operating history. As a result, the assumptions and estimates regarding the performance of these projects are and will be made without the benefit of a meaningful operating history. The ability of such projects to perform as expected will also be subject to risks inherent in newly constructed generation and transmission projects, including, but not limited to, equipment performance below the Corporation's expectations, unexpected component failures and product defects, and generation and transmission system failures and outages. The failure of some or all of the projects to perform as expected could have a material adverse effect on the Corporation's business, results of operations, financial condition and cash flows.

The Corporation's financial performance may be adversely affected by fluctuations in commodity prices.

Market prices for power, generation capacity, ancillary services and natural gas are unpredictable and tend to fluctuate substantially, which may affect the Corporation's operating results. With respect to the Regulated Services Group, commodity price exposure is primarily limited to the cost of electricity and natural gas. Although the Regulated Services Group's utility rates and tariffs are generally designed to allow recovery of commodity costs, timing differences and other factors, which may be exacerbated by fluctuating prices, may result in less than full recovery.

Lower prices for other fuel sources may reduce the demand for the electrical energy generated and sold by the Renewable Energy Group.

Demand for the electrical energy generated by Renewable Energy Group's electric generation assets is affected by the price and availability of other fuels, including, but not limited to, nuclear, coal and oil. To the extent renewable energy becomes less cost-competitive due to reduced or eliminated government renewable energy targets and other tax credits and incentives that favour renewable energy, cheaper alternatives or otherwise, demand for renewable energy could decrease. Slow growth or a long-term reduction in renewable energy demand could have a material adverse effect on the Corporation's business, results of operations, financial condition and cash flows.

Cash flow deferrals related to energy commodities can be significant.

The Corporation is permitted to collect from customers only amounts approved by regulatory commissions. However, the Corporation's costs to provide utility services can be much higher or lower than the amounts currently billed to customers. The Corporation is permitted to defer income statement recognition and recovery from customers for some of these differences, which are recorded as deferred charges with the opportunity for future recovery through retail rates. These deferred costs are subject to review for prudence and potential disallowance by regulators, who have discretion as to the extent and timing of future recovery or refund to customers.

Power and natural gas costs higher than those recovered in retail rates reduce cash flows. Amounts that are not allowed for deferral or which are not approved to become part of customer rates affect the Corporation's results of operations.

Even if the regulators ultimately allow the Corporation to recover deferred power and natural gas costs, the Corporation's operating cash flows can be negatively affected until these costs are recovered from customers.

The Regulated Services Group is obligated to serve utility customers within its certificated service territories, which may require that the Corporation make capital expenditures and incur indebtedness to expand service to new customers.

The Regulated Services Group may have facilities located within areas experiencing growth. These utilities may have an obligation to service new residential, commercial and industrial customers. While expansion to serve new customers could result in increased future cash flows, it may require significant capital commitments in the immediate term. Accordingly, the Regulated Services Group may be required to solicit additional capital or incur additional borrowings to finance these future construction obligations.

As a holding company, the Corporation does not have its own operating income and must rely on the cash flows from its subsidiaries to pay dividends and make debt payments.

The Corporation is a holding company with no significant operations of its own, and the Corporation's primary assets are shares or other ownership interests of its subsidiaries. The Corporation's subsidiaries are separate and distinct legal entities and may have no obligation to pay any amounts to the Corporation, whether through dividends, loans or other means. The ability of the Corporation's subsidiaries to pay dividends or make distributions to the Corporation depends on several factors, including each subsidiary's actual and projected earnings and cash flow, capital requirements and general financial condition, regulatory restrictions, covenants contained in credit facilities to which they are parties, and the prior rights of holders of their existing and future secured debt and other debt or equity securities. Further, the amount and payment of dividends from any subsidiary is at the discretion of such subsidiary's board of directors, which may reduce or cease payment of dividends at any time. In addition, there may be changes to tax regulation affecting the repatriation of dividends from other countries, which may negatively affect the Corporation.

The Corporation and its subsidiaries are not able to insure against all potential risks and may become subject to higher insurance premiums, and the Corporation's ability to obtain insurance and the terms of any available insurance coverage could be materially adversely affected by international, national, state or local events and company-specific events, as well as the financial condition of insurers.

The Corporation maintains insurance coverage for certain exposures, but this coverage is limited and the Corporation is generally not fully insured against all significant losses. Such insurance may not continue to be offered on an economically feasible basis and may not cover all events that could give rise to a loss or claim involving the Corporation's assets or operations. The Corporation's ability to obtain and maintain insurance and the terms of any available insurance coverage could be materially adversely affected by international, national, state or local events and company-specific events, as well as the financial condition of insurers.

If the Corporation were to incur a serious uninsured loss or a loss significantly exceeding the limits of its insurance policies, the results could have a material adverse effect on the Corporation's business, results of operations, financial condition and cash flows. In the event of a large uninsured loss caused by severe weather conditions, natural disasters and certain other events beyond the control of the Regulated Services Group, the Corporation may make an application to an applicable regulatory authority for the recovery of these costs through customer rates to offset any loss. However, the Corporation cannot provide assurance that the regulatory authorities would approve any such application in whole or in part. This potential recovery mechanism is not available to the Renewable Energy Group.

The Corporation is subject to litigation or administrative proceedings, which may adversely impact the Corporation's consolidated financial position, results of operations and cash flows.

The Corporation has been and continues to be involved in legal proceedings, administrative proceedings, claims and other litigation that arise in the ordinary course of its business. These actions may include contractual disputes, employment-related claims, securities-based litigation and claims for personal injury or property damage that occur in connection with services performed relating to the operation of the Corporation's business, or actions by regulatory or tax authorities. The final outcome with respect to such legal proceedings cannot be predicted with certainty, and unfavourable outcomes or developments relating to these proceedings or future proceedings, such as judgments for monetary damages, injunctions, denial or revocation of permits or settlement of claims, could have an adverse effect on the Corporation's financial condition, results of operations and cash flows. Even if the Corporation prevails in any such legal proceedings, the proceedings could be costly, time-consuming and divert the attention of management and other personnel, which could adversely affect the Corporation.

4.2 Risk Factors Relating to Financing and Financial Reporting

A downgrade in APUC's credit ratings or the credit ratings of its subsidiaries could have a material adverse effect on the Corporation's business, cost of capital, financial condition and results of operations.

APUC has long-term consolidated corporate credit ratings of BBB from S&P, BBB from DBRS and BBB from Fitch. The ratings indicate the agencies' assessment of the ability to pay the interest and principal of debt securities issued by the Corporation. See "*Description of the Business – Credit Ratings*".

There can be no assurance that any of the current ratings of the Corporation will remain in effect for any given period of time or that a rating will not be lowered or withdrawn entirely by a rating agency if, in its judgment, circumstances in the future so warrant. Factors rating agencies typically consider in evaluating the creditworthiness of a business such as APUC's include but are not limited to the following: amount of leverage used in the business, the business mix including the relative contribution to EBITDA of regulated utility operations versus non-regulated operations and the countries in which the business operates. Negative changes in these and other factors a rating agency deems to be significant that are expected to be prolonged could result in a credit rating downgrade. A downgrade in credit ratings would result in an increase in the Corporation's borrowing costs under its bank credit facilities and future issuances of long-term debt securities. Any such downgrade could also adversely impact the market price of the outstanding securities of the Corporation, and could require the Corporation to post additional collateral security under some of its contracts and hedging arrangements. If any of these ratings fall below investment grade (defined as BBB- or above for S&P and Fitch and BBB (low) or above for DBRS), the Corporation's ability to issue short-term debt or other securities, or to market those securities, may be impaired or become more difficult or expensive. Therefore, any such downgrades could have a material adverse effect on the Corporation's business, cost of capital, financial condition and results of operations. Each rating agency employs proprietary scoring methodologies that assess business and financial risks of the entity rated. There can be no assurance that the principles on which the rating is based remain consistently applied, and these principles are subject to change from time to time at each rating agency's discretion. For example, the rating agency's views on total allowable leverage, specific industry risk factors, country risk and the company's business mix, amongst other factors, may change. Such changes could require APUC to adjust its business and strategy in order to maintain its credit ratings. APUC currently anticipates that to continue to maintain a BBB flat investment grade credit rating, it will, amongst other things, need to execute its growth strategy in a manner that preserves satisfaction of financial leverage targets and continues to generate no less than approximately its current portion of EBITDA (as determined by applicable rating agency methodologies) from APUC's Regulated Services Group. There can be no assurance that APUC will be successful, and the failure to do so could have a negative impact on APUC's credit ratings.

Financial market disruptions or other factors could increase financing costs or limit access to credit and capital markets, which could adversely affect the Corporation's ability to refinance existing indebtedness on favourable terms, execute its acquisition and investment strategy, and finance its other activities upon favourable terms.

As of December 31, 2019, the Corporation had substantial indebtedness. Management of the Corporation believes, based on its current expectations as to the Corporation's future performance, that the cash flow from operations, the funds available under its credit facilities and its ability to access capital markets will be adequate to enable the Corporation to finance its operations, execute its business strategy and maintain an adequate level of liquidity. However, the Corporation's expected revenue and capital expenditures are only estimates. Moreover, actual cash flows from operations will depend on regulatory, market and other conditions that are beyond the Corporation's control. As a result, there can be no assurance that management's expectations as to future performance will be realized.

The Corporation's ability to raise additional debt or equity, on favourable terms or at all, may be adversely affected by any adverse financial and operational performance or by financial market disruptions or other factors outside the Corporation's control.

In addition, the Corporation may at times incur indebtedness in excess of its long-term leverage targets, in advance of raising the additional equity capital necessary to repay such indebtedness and maintain its long-term leverage target. Any increase in the Corporation's leverage could, among other things: limit the Corporation's ability to obtain additional financing for working capital, investment in subsidiaries, capital expenditures, debt service requirements, acquisitions and general corporate or other purposes; restrict the Corporation's flexibility and discretion to operate its business; limit the Corporation's ability to declare dividends; require the Corporation to dedicate a portion of cash flows from operations to the payment of interest on its existing indebtedness, in which case such cash flows would not be available for other purposes; cause ratings agencies to re-evaluate or downgrade the Corporation's existing credit ratings; expose the Corporation to increased interest expense on borrowings at variable rates; limit the Corporation's ability to adjust to changing market conditions; place the Corporation at a competitive disadvantage compared to its competitors; make the Corporation vulnerable to any downturn in general economic conditions; and render the Corporation unable to make expenditures that are important to its future growth strategies.

The Corporation will need to refinance its existing consolidated indebtedness over time. There can be no assurance that the Corporation will be successful in refinancing its indebtedness when necessary or that additional financing will be obtained when needed, on commercially reasonable terms or at all. In the event that the Corporation cannot refinance indebtedness or raise additional indebtedness, or if the Corporation cannot refinance its indebtedness or raise additional indebtedness on terms that are not less favourable than the current terms, the Corporation's cash flows and ability to declare dividends may be adversely affected.

The Corporation's ability to meet its debt service requirements will depend on its ability to generate cash in the future, which depends on many factors, including the Corporation's financial performance, debt service obligations, the realization of the anticipated benefits of acquisition and investment activities, and working capital and capital expenditure requirements. In addition, the Corporation's ability to borrow funds in the future to make payments on outstanding debt will depend on the satisfaction of covenants in existing credit agreements and other agreements. A failure to comply with any covenants or obligations under the Corporation's consolidated indebtedness could result in a default under one or more such instruments, which, if not cured or waived, could result in the termination of dividends by the Corporation and permit acceleration of the relevant indebtedness. There can be no assurance that, if such indebtedness were to be accelerated, the Corporation's assets would be sufficient to repay such indebtedness in full. There can also be no assurance that the Corporation will generate cash flow in amounts sufficient to pay its outstanding indebtedness or to fund the Corporation's other liquidity needs.

Sustained increases in interest rates could negatively affect the Corporation's financing costs, ability to access capital and ability to continue successfully implementing its business strategy.

The Corporation is exposed to interest rate risk from certain outstanding variable interest indebtedness. As a result, increases in interest rates could materially increase the Corporation's financing costs and adversely affect its results of operations, cash flows, borrowing capacity and ability to implement its business strategy.

Currency exchange rate fluctuations may affect the Corporation's financial results and increase certain financing risks.

Currency fluctuations may affect the cash flows the Corporation realizes from its consolidated operations because a significant portion of the Corporation's revenues are generated in U.S. dollars. Although the Corporation may enter into derivative contracts to hedge currency exchange rate exposure, the Corporation typically does not hedge its full exposure. If the Corporation does enter into currency hedges and exchange rates move in a favourable direction, such currency hedges may reduce or eliminate the Corporation's realization of the benefit of favourable exchange rate movement. In addition, currency hedging transactions will be subject to risks that the applicable counterparty may prove unable or unwilling to perform their obligations under the contracts, as a result of which the Corporation would lose some or all of the anticipated benefits of such hedging transactions.

The Corporation is, and will continue to be, party to agreements, including credit agreements and indentures, that contain covenants that restrict its financial flexibility.

The Corporation's existing credit facilities contain covenants imposing certain requirements on the Corporation's business including covenants regarding the ratio of indebtedness to total capitalization. Furthermore, APUC and its subsidiaries have, and may continue to, periodically issue long-term debt, which may consist of both secured and unsecured indebtedness. These third-party debt agreements also contain covenants, including covenants regarding the ratio of indebtedness to total capitalization. These requirements may limit the Corporation's ability to take advantage of potential business opportunities as they arise and may adversely affect the Corporation's conduct and the current business of certain operating subsidiaries, including restricting the ability to finance future operations and capital needs and limiting the subsidiaries' ability to engage in other business activities. Other covenants place or could place restrictions on the Corporation's ability and the ability of its operating subsidiaries to, among other things, incur additional debt, create liens, and sell or transfer assets.

Agreements the Corporation enters into in the future may also have similar or more restrictive covenants, especially if the general credit market deteriorates. A breach of any covenant in the existing credit facilities or the agreements governing the Corporation's other indebtedness would result in an event of default. Certain events of default may trigger automatic acceleration of payment of the underlying obligations or may trigger acceleration of payment if not remedied within a specified period. Events of default under one agreement may trigger events of default under other agreements, although the Corporation's regulated utilities are not subject to the risk of default of affiliates. Should payments become accelerated as the result of an event of default, the principal and interest on such borrowing would become due and payable immediately. If that should occur, the Corporation may not be able to make all of the required payments or borrow sufficient funds to refinance the accelerated debt obligations. Even if new financing is then available, it may not be on terms that are acceptable to the Corporation.

A significant portion of the Corporation's debt will mature over the next five years and will need to be paid or refinanced, and changes to the debt and equity markets could adversely affect the Corporation's business.

A significant portion of the Corporation's debt is set to mature in the next five years, including its revolving credit facility. The Corporation may not be able to refinance its maturing debt on commercially reasonable terms, or at all, depending on numerous factors, including its financial condition and prospects at the time and the then current state of the banking and capital markets in Canada and the United States.

Challenges to the Corporation's tax positions, and changes in applicable tax laws, could materially and adversely affect returns to the Corporation's shareholders.

The Corporation is subject to income and other taxes primarily in the United States and Canada. Changes in tax laws or interpretations thereof in the jurisdictions in which we do business could adversely affect the Corporation's results from operations, returns to shareholders and cash flow.

The Corporation cannot provide assurance that the Canada Revenue Agency, the Internal Revenue Service or any other applicable taxation authority will agree with the tax positions taken by the Corporation, including with respect to claimed expenses and the cost amount of the Corporation's depreciable properties. A successful challenge by an applicable taxation authority regarding such tax positions could adversely affect the results of operations and financial position of the Corporation.

Development by the Corporation of renewable power generation facilities in the United States depends in part on federal tax credits and other tax incentives. These credits are currently subject to a multi-year step-down. While recently enacted U.S. tax reform legislation did extend some of the credits, at reduced levels, for renewable power generation facilities that begin construction in 2020, there can be no assurance that there will be further extensions in the future or that the reduced credits will be sufficient to support continued development and construction of renewable power facilities in the United States. Moreover, if the Corporation is unable to complete construction on current or planned projects on anticipated schedules, the reduced incentives may be insufficient to support continued development or may result in substantially reduced financial benefits from facilities that the Corporation is committed to complete. In addition, the Corporation has entered into certain tax equity financing transactions with financial partners for certain of its renewable power facilities in the United States, under which allocations of future cash flows to the Corporation from the applicable facility could be adversely affected in the event that there are changes in U.S. tax laws that apply to facilities previously placed in service.

On December 22, 2017, H.R. 1, the Tax Cuts and Jobs Act was signed into law which resulted in significant changes to U.S. tax law that will affect the Corporation. The U.S. Department of Treasury has released proposed regulations related to business interest expense limitations, Base Erosion Anti-Abuse Tax, and anti-hybrid structures as part of the implementation of U.S. tax reform. Some of the proposed regulations were finalized during 2019. Many of the regulations are still in proposed form and are subject to change in the regulatory review process which is expected to be completed during 2020. The timing or impacts of any future changes in tax laws, including the impacts of proposed regulations, cannot be predicted. As a result, there may be future impacts on the results of operations, financial condition and cash flows of the Corporation.

The Corporation is subject to funding risks associated with defined benefit pension and OPEB plans.

Certain utility businesses acquired by the Corporation maintain defined benefit pension plans covering substantially all of the employees of the acquired business, and other post-employment benefit ("**OPEB**") plans for eligible retired employees, including retiree health care and life insurance benefits. The Corporation also provides a defined benefit cash balance pension plan covering substantially all its new employees and current employees at its water utilities, under which employees are credited with a percentage of base pay plus a prescribed interest rate credit.

Future contributions to the Corporation's plans are impacted by a number of variables, including the investment performance of the plans' assets and the discount rate used to value the liabilities of the plans. If capital market returns are below assumed levels, or if discount rates decrease, the Corporation could be required to make contributions to its plans in excess of those currently expected, which would adversely affect the Corporation's cash flows.

The Corporation is subject to credit risk of customers and other counterparties.

The Corporation is subject to credit risk with respect to the ability of customers and other counterparties to perform their obligations to the Corporation, including paying amounts that they owe to the Corporation. This credit risk exists with respect to utility customers, as well as counterparties to long-term PPAs, supply agreements and derivative financial instruments, among others.

Adverse conditions in the energy industry or in the general economy, as well as circumstances of individual customers or counterparties, may adversely affect the ability of a customer or counterparty to perform as required under its contract with the Corporation. Losses from a utility customer may not be offset by bad debt reserves approved by the applicable utility regulator. If a customer under a long-term PPA is unable to perform, the Renewable Energy Group may be unable to replace the contract on comparable terms, in which case sales of power (and, if applicable, renewable energy credits and ancillary services) from the facility would be subject to market price risk and may require refinancing of indebtedness related to the facility or otherwise have a material adverse effect. Default by other counterparties, including counterparties to supply and construction contracts, to hedging contracts that are in an asset position, and to short-term investments, also could adversely affect the financial results of the Corporation.

The Corporation makes certain assumptions, judgments and estimates that affect amounts reported in its consolidated financial statements, which, if not accurate, may adversely affect its financial results.

APUC prepares its consolidated financial statements in accordance with U.S. GAAP. The preparation of consolidated financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, related amounts of revenues and expenses, and disclosure of contingent assets and liabilities. Significant areas requiring the use of management judgment include the scope of consolidated entities, useful lives and recoverability of depreciable assets, the measurement of deferred taxes and the recoverability of deferred tax assets, rate-regulation, unbilled revenue, asset retirement obligations, pension and post-employment benefits, fair value of derivatives and fair value of assets and liabilities acquired in a business combination. Actual results may differ from these estimates and any inaccuracies in these estimates could result in the Corporation incurring significant expenses and adversely affect the Corporation's financial results.

As a foreign private issuer, APUC is subject to different U.S. securities laws and rules than a domestic U.S. issuer, which may limit the information publicly available to shareholders.

APUC is a "foreign private issuer," as such term is defined in Rule 405 under the U.S. Securities Act of 1933, as amended, and is permitted, under a multijurisdictional disclosure system adopted by the U.S. and Canada, to prepare its disclosure documents under the U.S. Securities Exchange Act of 1934, as amended (the "**U.S. Exchange Act**") in accordance with Canadian disclosure requirements. Under the U.S. Exchange Act, APUC is subject to reporting obligations that, in certain respects, are less detailed and less frequent than those of U.S. domestic reporting companies. As a result, APUC does not file the same reports that a U.S. domestic issuer would file with the U.S. Securities and Exchange Commission (the "**SEC**"), although APUC is required to file or furnish to the SEC the continuous disclosure documents that it is required to file in Canada under Canadian securities laws. In addition, APUC's officers, directors, and principal shareholders are exempt from the reporting and "short swing" profit recovery provisions of Section 16 of the U.S. Exchange Act. Therefore, APUC's shareholders may not know on as timely a basis when APUC's officers, directors and principal shareholders purchase or sell shares, as the reporting deadlines under the corresponding Canadian insider reporting requirements are longer.

As a foreign private issuer, APUC is exempt from the rules and regulations under the U.S. Exchange Act related to the furnishing and content of proxy statements. APUC is also exempt from Regulation FD, which prohibits issuers from making selective disclosures of material non-public information. While APUC will comply with the corresponding requirements relating to proxy statements and disclosure of material non-public information under Canadian securities laws, these requirements differ from those under the U.S. Exchange Act and Regulation FD and shareholders should not expect to receive the same information at the same time as such information is provided by U.S. domestic companies. In addition, APUC has four months after the end of each fiscal year to file its annual information form with the SEC and is not required under the U.S. Exchange Act to file quarterly reports with the SEC as promptly as U.S. domestic companies whose securities are registered under the U.S. Exchange Act.

In addition, as a foreign private issuer, APUC has the option to follow certain Canadian corporate governance practices, except to the extent that such laws would be contrary to U.S. securities laws, and provided that APUC discloses the requirements that it is not following and describe the Canadian practices it follows instead. APUC currently relies on this exemption with respect to requirements regarding the quorum for any meeting of its shareholders. APUC may in the future elect to follow home country practices in Canada with regard to other matters. As a result, APUC's shareholders may not have the same protections afforded to shareholders of U.S. domestic companies that are subject to all U.S. corporate governance requirements.

4.3 Risk Factors Relating to Regulatory Environment

The profitability of the Corporation's businesses depends in part on regulatory climates in the jurisdictions in which it operates, and the failure to maintain required regulatory authorizations could materially and adversely affect the Corporation.

The utility commissions in the jurisdictions in which the Regulated Services Group operates regulate many aspects of its utility operations, including the rates that the Regulated Services Group can charge customers, siting and construction of facilities, pipeline safety and compliance, customer service and the utility's ability to recover the costs that it incurs, including capital expenditures and fuel and purchased power costs.

A fundamental risk faced by any regulated utility is the disallowance by the utility's regulator of costs requested to be placed into the utility's revenue requirement. In addition, the time between the incurrence of costs and the granting of the rates to recover those costs by state or provincial regulatory agencies – known as "regulatory lag" – can adversely affect profitability. If the Corporation is unable to recover increased costs of operations or its investments in new facilities, or in the event of significant regulatory lag, the Corporation's results of operations could be adversely affected.

In addition, there is a risk that the utility's regulator will not approve the revenue requirements requested in outstanding or future applications for rates or will, on its own initiative, seek to reduce the existing revenue requirements. Rate applications for revenue requirements are subject to the utility regulator's review process, usually involving participation from intervenors and a public hearing process. There can be no assurance that resulting decisions or rate orders issued by the utility regulators will permit the Corporation to recover all costs actually incurred, costs of debt and income taxes, or to earn a particular return on equity. A failure to obtain acceptable rate orders, or approvals of appropriate returns on equity and costs actually incurred, may materially adversely affect: the Regulated Services Group's businesses, the undertaking or timing of capital expenditures, ratings assigned by credit rating agencies, the cost and issuance of long-term debt, and other matters, any of which may in turn have a material adverse effect on the Corporation. In addition, there is no assurance that the Corporation will receive regulatory decisions in a timely manner and, therefore, costs may be incurred prior to having an approved revenue requirement.

In the case of some of the Corporation's hydroelectric generating facilities, water rights are owned by governments that reserve the right to control water levels, which may affect revenue, while in the United States, hydroelectric generating facilities are required to be licensed or have valid exemptions from FERC. The failure to obtain all necessary licenses or permits for such facilities, including renewals thereof or modifications thereto, may result in an inability to operate the facility and could adversely affect cash generated from operating activities.

FERC has jurisdiction over wholesale rates for all electric energy sold by the Renewable Energy Group in the United States. Certain Renewable Energy Group's facilities in the United States are required to meet the requirements of a "qualifying facility" or an "exempt wholesale generator" and, subject to certain exceptions, to obtain and maintain authority from FERC to sell power at market-based rates. The failure of the Renewable Energy Group to obtain or maintain, as applicable, market-based rate authorization for its facilities could materially and adversely affect the Corporation.

Additionally, owners, operators and users of the bulk electric system in the United States are subject to mandatory reliability standards developed by the NERC and its regional entities. Increased reliability standard compliance obligations may cause higher operating costs or capital expenditures for the Corporation's utilities.

The operations of each of the Corporation's business units are also subject to a variety of federal, provincial and state environmental and other regulatory bodies, the requirements and regulations of which affect the operations of, and costs incurred by, the Corporation. If any of the Corporation's business units were found to be in violation of applicable requirements or regulations, they could also be subject to significant penalties. In addition, changes in regulations or the imposition of additional regulations also could have a material adverse effect on the Corporation's results of operations.

The Corporation's operations are subject to numerous health and safety laws and regulations that could adversely affect its business, financial condition and results of operations.

The operation of the Corporation's facilities requires adherence to safety standards imposed by regulatory bodies. These laws and regulations require the Corporation to obtain approvals and maintain permits, undergo environmental impact assessments and review processes and implement environmental, health and safety programs and procedures to control risks associated with the siting, construction, operation and decommissioning of energy projects. Failure to operate the facilities in strict compliance with these regulatory standards may expose the facilities to claims and administrative sanctions.

Health and safety laws, regulations and permit requirements may change or become more stringent. Any such changes could require the Corporation to incur materially higher costs than the Corporation has incurred to date. The Corporation's costs of complying with current and future health and safety laws, regulations and permit requirements, and any liabilities, fines or other sanctions resulting from violations of them, could adversely affect its business, financial condition and results of operations.

The Corporation is subject to numerous environmental laws, regulations and other standards that may result in capital expenditures, increased operating costs and various liabilities.

The Corporation is subject to extensive federal, state, provincial and local regulation with regard to air and other environmental matters. Failure to comply with these laws and regulations could have a material adverse effect on the Corporation's results of operations and financial position. In addition, new environmental laws and regulations, and new interpretations of existing environmental laws and regulations, have been adopted and may in the future be adopted, which may substantially increase the Corporation's future environmental expenditures. Although the Regulated Services Group has historically recovered such costs through regulated customer rates, there can be no assurance that the Regulated Services Group will recover all or any part of such increased costs in future rate cases. The Renewable Energy Group generally has no right to recover such costs from customers. The incurrence of additional material environmental costs which are not recovered in utility rates may have a material adverse effect on the Corporation's business, financial condition and results of operations.

The Corporation may pursue growth opportunities in new markets that are subject to foreign laws and regulations that are more onerous than the laws and regulations to which it is currently subject.

The Corporation may pursue growth opportunities in new markets that are subject to regulation by various foreign governments and regulatory authorities and to the application of foreign laws. Such foreign laws or regulations may not provide the same type of legal certainty and rights, in connection with the Corporation's contractual relationships in such countries, as are afforded to the Corporation in Canada and the U.S., which may adversely affect the Corporation's ability to receive revenues or enforce its rights in connection with any operations or projects in such jurisdictions. In addition, the laws and regulations of some countries may limit the Corporation's ability to hold a majority interest in certain projects, thus limiting the Corporation's ability to control the operations of such projects. Any existing or new operations or interests of the Corporation may also be subject to significant political, economic and financial risks, which vary by country, and may include: (i) changes in government policies or personnel; (ii) changes in general economic conditions; (iii) restrictions on currency transfer or convertibility; (iv) changes in labour relations; (v) political instability and civil unrest; (vi) regulatory or other changes adversely affecting the local utility market; and (vii) breach or repudiation of important contractual undertakings by governmental entities and expropriation and confiscation of assets and facilities for less than fair market value.

4.4 Risk Factors Relating to Strategic Planning and Execution

The Corporation is subject to risks associated with its growth strategy that may adversely affect its business, results of operations, financial condition and cash flows, and actual capital expenditures may be lower than planned.

The Corporation has a history of growth through acquisitions and organic growth from development projects and capital expenditures in existing service territories. There is no certainty that the Corporation will be successful in pursuing this growth strategy in the future. There can be no assurance that the Corporation will be able to identify attractive acquisition or development candidates in the future or that it will be able to realize growth opportunities that increase the amount of cash available for distribution. The Corporation's growth strategy may be constrained by factors associated with the maintenance of its BBB flat investment grade credit rating. These factors include: (i) constraints on maximum leverage, (ii) the proportion of EBITDA (as determined by applicable rating agency methodologies) required to be generated from the Regulated Services Group, and (iii) the geographies in which APUC can operate in scale. There can be no assurance that these constraints will not negatively impact the Corporation's ability to successfully execute on available growth opportunities. The Corporation may also face significant competition for growth opportunities and, to the extent that any opportunities are identified, may be unable to effect such growth opportunities due to a lack of necessary or cost competitive capital resources. Risks related to capital projects include schedule delays and project cost overruns. There is no assurance that any project cost overruns would be approved for recovery in customer rates.

Any growth opportunity could involve potential risks, including an increase in indebtedness, the potential disruption to the Corporation's ongoing business, the diversion of management's attention from other business concerns and the possibility that the Corporation will incur more costs than originally anticipated or, in the case of acquisitions, more than the acquired company or interest is worth. In addition, funding requirements associated with the growth opportunity, including any acquisition, development or integration costs, may reduce the funds available to pay dividends.

The Regulated Services Group's capital expenditure program and associated rate base growth are key assumptions in the Corporation's targeted dividend growth guidance. Actual capital expenditures may be lower than planned due to factors beyond the Corporation's control, which would result in a lower than anticipated rate base and have an adverse effect on the Corporation's results of operations, financial condition and cash flows. This could limit the Corporation's ability to meet its targeted dividend growth.

The Corporation's development and construction activities are subject to material risks, including expenditures for projects that may prove not to be viable, construction cost overruns and delays, inaccurate estimates of expected energy output or other factors, and failure to satisfy tax incentive requirements or to meet third-party financing requirements.

The Corporation actively engages in the development and construction of new power generation facilities, and currently has a pipeline of projects in development or construction, consisting mainly of solar and wind power generation projects, as well as the development and construction of transmission and distribution assets. In addition, each of the Corporation's business segments may occasionally undertake construction activities as part of normal course maintenance activities.

Significant costs must be incurred to determine the technical feasibility of a project, obtain necessary regulatory approvals and permits, obtain site control and interconnection rights and negotiate revenue contracts for the facility before the viability of the project can be determined. Regulatory approvals can be challenged by a number of mechanisms which vary across state and provincial jurisdictions. Such permitting challenges could identify issues that may result in permits being modified or revoked, or the failure of a project to proceed and the resultant loss of amounts invested or expenses already incurred.

Material delays or cost overruns could be incurred by the Corporation and its development and construction projects as a result of vendor or contractor non-performance, technical issues with the interconnection utility, disputes with landowners or other parties, severe weather and other causes.

The Corporation's assessment of the feasibility, revenues and profitability of a renewable power generation facility depends upon estimates regarding the strength and consistency of the applicable natural resource (such as wind, solar radiance or hydrology) and other factors, such as assessments of the facility's potential impact on wildlife. If weather patterns change or actual data proves to be materially different than estimates, the amount of electricity to be generated by the facility and resulting revenues and profitability may differ significantly from expected amounts.

For certain of its development projects, the Renewable Energy Group relies on financing from third party tax equity investors, the participation of which depends upon qualification of the project for U.S. tax incentives and satisfaction of the investors' investment criteria. These investors typically provide funding upon commercial operation of the facility. Should certain facilities not meet the conditions required for tax equity funding, expected returns from the facilities may be adversely impacted.

The Corporation's construction activities relating to its utility and power generation projects utilize a variety of products and materials. The cost to the Corporation of such products and materials may be impacted by a number of factors beyond the Corporation's control, including their general availability and the impact of tariffs and duties imposed by various governmental authorities. While the Regulated Services Group may be able to recover any such increased costs in future rate cases, there is generally no such recovery mechanism available to the Renewable Energy Group for such costs. The financial condition and results of operations of the Corporation may be impacted as a result.

Energy generated by the Corporation is often sold under long-term PPAs. PPAs generally contain customary terms including: the amount paid for energy from the project over the term of the agreement (which rate can be materially higher than prevailing market rates) and a requirement for the project to comply with technical standards and to achieve commercial operation within time frames prescribed by the contract. A failure to achieve satisfactory construction progress and/or the occurrence of any permitting or other unanticipated delays at a project could result in a failure to comply with the applicable PPA requirements within the specified time frames. Remedies for failure to comply with material provisions of a PPA generally include, among other things, the potential termination of the agreement by the non-defaulting party. Any such termination could have a material adverse effect on the Corporation's results of operations and financial position.

The Renewable Energy Group depends on certain key customers for a significant portion of its revenues. The loss of any key customer or the failure to secure new PPAs, renew existing PPAs or enter into long-term energy production hedge arrangements could increase market price risk with respect to the sale of generated energy and renewable energy credits.

A substantial portion of the output of the Renewable Energy Group's power generation facilities is sold under long-term PPAs, under which a single purchaser is obligated to purchase all of the output of the applicable facility and (in most cases) associated renewable energy credits. The production at certain of the Renewable Energy Group's power generation facilities also are subject to long-term energy production hedge arrangements. The termination or expiry of any such PPA or long-term energy production hedge arrangement, unless replaced or renewed on equally favourable terms, would adversely affect the Corporation's results of operations and cash flows and increase the Corporation's exposure to risks of price fluctuations in the wholesale power market.

Securing new PPAs is a risk factor in light of the competitive environment in which the Corporation operates. The Corporation expects the Renewable Energy Group to continue to enter into PPAs for the sale of its power, which PPAs are mainly obtained through participation in competitive requests for proposals processes. During these processes, the Corporation faces competitors ranging from large utilities to small independent power producers, some of which have significantly greater financial and other resources than the Corporation. There can be no assurance that the Corporation will be selected as power supplier following any particular request for proposals in the future or that existing PPAs will be renewed or will be renewed on favourable terms and conditions upon the expiry of their respective terms.

The Corporation may fail to complete planned acquisitions, which may result in a loss of expected benefits from such acquisitions or may generate significant liabilities.

Acquisitions of businesses and technologies are a part of the Corporation's overall business strategy. Because of the regulated nature of certain of the business sectors in which the Corporation operates, certain acquisitions by the Corporation, including the acquisition of New York American Water and the acquisition of Ascendant, are subject to various regulatory approvals and, consequently, to the risks that such approvals may not be timely obtained or may impose unfavourable conditions that could impair the ability to complete the acquisition or impose adverse conditions on the Corporation following the acquisition.

In addition, the Corporation may pursue acquisition opportunities through participation in competitive auction processes. During these processes, the Corporation may face competition from other companies with greater purchasing power, capital or other resources or a greater willingness to accept lower returns or risk. The outcomes of such processes are uncertain and the Corporation may fail to win such bids.

Further, the Corporation may enter into acquisition agreements under which the Corporation's obligations are not contingent upon availability of financing, in which case the Corporation could incur higher than expected financing costs or, if such financing cannot be obtained, significant liability to the seller.

The Corporation may fail to realize the intended benefits of completed acquisitions or may incur unexpected costs or liabilities as a result of completed acquisitions.

The Corporation may not effectively integrate the services, technologies, key personnel or businesses of acquired companies or may not obtain anticipated operating benefits or synergies from completed transactions. In addition, the Corporation may incur unexpected costs or liabilities in connection with the closing or integration of any acquisition.

The success of an acquisition may depend on retention of the workforce or key employees of the acquired business. The Corporation may not be successful in retaining such workforce or key employees or in retaining them at anticipated costs.

In addition, the Corporation may be subject to unexpected liabilities, despite any due diligence investigation of an acquired business or any contractual remedies the Corporation may have against the seller. Detailed information regarding an acquired business is generally available only from the seller, and contractual remedies are typically subject to negotiated limitations. In addition, in cases in which the target company is publicly traded and its shares are widely held, the Corporation is likely not to have recourse following the completion of the acquisition for misrepresentations made to the Corporation in connection with the acquisition.

The Corporation's investment in Atlantica is subject to risks, including that the market price of Atlantica's securities could decline or Atlantica may make decisions with which the Corporation does not agree or take risks or otherwise act in a manner that does not serve the Corporation's interests.

The Corporation owns an equity interest in Atlantica of approximately 44.2%. This investment is subject to a risk that Atlantica may make business, financial or management decisions with which the Corporation does not agree, or that Atlantica's other stockholders or management of Atlantica may take risks or otherwise act in a manner that does not serve the Corporation's interests. If any of the foregoing were to occur, the value of the Corporation's investment could decrease and the Corporation's financial condition, results of operations and cash flows could be adversely affected.

During 2019 Atlantica announced it was going to undertake a strategic review process. The results of this process have not yet been announced and the outcome is uncertain. Atlantica's share price may be adversely affected by the outcome of the strategic review, which would in turn could negatively affect Corporation's results.

Dividends declared and paid by Atlantica are made at the discretion of Atlantica's board of directors. The Corporation does not control the board of directors of Atlantica. Therefore, there can be no assurance that dividends will continue to be paid on Atlantica's ordinary shares, will continue to be paid at the same rate as they are currently being paid or will be paid at any specified target rate.

Demand in the capital markets for Atlantica's ordinary shares can vary over time for numerous reasons outside of the Corporation's control, including performance of the Atlantica business and changes in the prospects of Atlantica. Consequently, it may be difficult for the Corporation to dispose of its anticipated interest in Atlantica at favourable times or prices.

The Corporation's investment in Atlantica and its international acquisition, development, construction and operating activities, including through AAGES, expose the Corporation to certain risks that are particular to certain international markets.

Atlantica owns, manages and acquires renewable energy, conventional power, electric transmission lines and water assets in certain jurisdictions where the Corporation may not operate. The Corporation, through its investment in Atlantica, is indirectly exposed to certain risks that are particular to the markets in which it operates, including, but not limited to, risks related to: conditions in the global economy; changes to national and international laws, political, social and macroeconomic risks relating to the jurisdictions in which Atlantica operates, including in emerging markets, which could be subject to economic, social and political uncertainties; anti-bribery and anti-corruption laws and substantial penalties and reputational damage from any non-compliance therewith; significant currency exchange rate fluctuations; Atlantica's ability to identify and/or consummate future acquisitions on favourable terms or at all; Atlantica's inability to replace, on similar or commercially favourable terms, expiring or terminated offtake agreements; termination or revocation of Atlantica's concession agreements or PPAs; and various other factors. These risks could affect the profitability and growth of Atlantica's business, and ultimately the profitability of the Corporation's anticipated investment therein.

The Corporation's international acquisition, development, construction and operating activities, including through the AAGES joint venture, expose the Corporation to similar risks and could likewise affect the profitability, financial condition and growth of the Corporation.

The Regulated Services Group's water, wastewater, electricity and natural gas distribution systems could be subject to condemnation or other methods of taking by government entities under certain conditions.

The Regulated Services Group's water, wastewater, electricity and natural gas distribution systems could be subject to condemnation or other methods of taking by government entities under certain conditions. Any taking by government entities would legally require that just and fair compensation be paid to the Regulated Services Group. However, the determination of such fair and just compensation will be undertaken pursuant to a legal proceeding and, therefore, there can be no assurance that the value received for those assets would reflect the value the Corporation attributes to such assets, that the value received would be above book value or that the Corporation would not recognize a loss.

Increased external stakeholder activism could have an adverse effect on the Corporation's business, operations or financial condition.

External stakeholders are increasingly challenging investor-owned utilities in the areas of climate change, sustainability, diversity, utility return on equity and executive compensation. In addition, public opposition to larger infrastructure projects and renewable energy projects in certain areas is common, which may impact the Corporation's capital programs, development activities and operations. The social acceptance by external stakeholders, including, in some cases, First Nations and other aboriginal peoples, local communities, landowners and other interest groups, may be critical to the Corporation's ability to find and develop new sites suitable for viable renewable energy projects. Failure to obtain proper social acceptance for a project may prevent the development and construction of a project and lead to the loss of all investments made in the development and the write-off of such prospective project. Failure to effectively respond to public opposition may adversely affect the Corporation's capital expenditure programs, and, therefore, future organic growth, which could adversely affect its results of operations, financial condition and cash flows.

The Corporation may not have sole control over the projects that it invests in with its partners, including Abengoa, or over the revenues and certain decisions associated with those projects, which may limit the Corporation's flexibility and financial returns with respect to these projects.

The Corporation has, and may in the future continue to have, an equity interest of 50% or less in certain projects and facilities, including those owned by AAGES. As a result, the Corporation will not control such projects and its interest may be subject to the decision-making of third parties. This may limit the Corporation's flexibility and financial returns with respect to these projects and facilities, and create a risk that the Corporation's joint venture partner may:

- have economic or business interests or goals that are inconsistent with the Corporation's economic or business interests or goals;
- take actions contrary to the Corporation's policies or objectives with respect to the Corporation's investments;
- contravene applicable anti-bribery laws that carry substantial penalties for non-compliance and could cause reputational damage and a material adverse effect on the business, financial position and results of operations of the joint venture and the Corporation;
- have to give its consent with respect to certain major decisions, including among others, decisions relating to funding and transactions with affiliates;
- become bankrupt, limiting its ability to meet calls for capital contributions and potentially making it more difficult to refinance or sell projects;
- become engaged in a dispute with the Corporation that might affect the Corporation's ability to develop a project; or
- have competing interests in the Corporation's markets that could create conflict of interest issues.

The Corporation's involvement with AAGES may present a reputational risk, including from the reputation of Abengoa. AAGES has obtained the AAGES Secured Credit Facility, which is collateralized through a pledge of the Atlantica ordinary shares held by AY Holdings. A collateral shortfall would occur if the net obligation (as defined in the credit agreement) would equal or exceed 50% of the market value of the Atlantica shares. In the event of a collateral shortfall, AAGES is required to post additional collateral in cash to reduce the net obligation to 40% of the total collateral provided (the "**Collateral Reset Level**"). If AAGES were unable to fund the collateral shortfall, the AAGES Secured Credit Facility lenders hold the right to sell Atlantica shares to reduce the facility to the Collateral Reset Level. The AAGES Secured Credit Facility is repayable on demand if Atlantica ceases to be a public company. If AAGES were unable to repay the amounts owed, the lenders would have the right realize on their collateral.

The Corporation may sell businesses or assets, which may be sold at a loss and which, regardless of the sales price, may reduce total revenues and net income.

For financial, strategic and other reasons, the Corporation may from time to time dispose of businesses or assets that it owns. Such disposals may result in recognition of a loss upon such a sale. In addition, as a result of divestitures, the Corporation's revenues and net income may decrease and its business mix may change.

The price of the Common Shares may be volatile and the value of shareholders' investments could decline.

The trading price and value of, and demand for, the Common Shares may fluctuate and depend on a number of factors, including:

- the risk factors described in this AIF;
- general economic conditions internationally and within Canada and the United States, including changes in interest rates;
- changes in electricity and natural gas prices;
- actual or anticipated fluctuations in the Corporation's quarterly and annual results and those of the Corporation's competitors;
- the Corporation's reputation, businesses, operations, results and prospects;
- the timing and amount of dividends, if any, declared on the Common Shares;
- future issuances of Common Shares or other securities by the Corporation;
- future mergers and strategic alliances;
- market conditions in the energy industry;
- changes in government regulation, taxes, legal proceedings or other developments;

- shortfalls in the Corporation's operating results from levels forecasted by securities analysts;
- investor sentiment toward the stock of energy companies in general;
- announcements concerning the Corporation or its competitors;
- maintenance of acceptable credit ratings or credit quality; and
- the general state of the securities markets.

These and other factors may impair the development or sustainability of a liquid market for the Common Shares and the ability of investors to sell Common Shares at an attractive price. These factors also could cause the market price and demand for the Common Shares to fluctuate substantially, which may adversely affect the price and liquidity of the Common Shares. These fluctuations could cause shareholders to lose all or part of their investment in Common Shares. Many of these factors and conditions are beyond the Corporation's control and may not be related to its operating performance.

If securities or industry analysts do not publish research or publish inaccurate or unfavourable research about the Corporation or its businesses, the price and trading volume of the Common Shares could decline.

The trading market for the Common Shares will, to some extent, be impacted by the research and reports that securities or industry analysts publish about the Corporation or its business. The Corporation does not have any control over these publications. If one or more of the analysts who cover the Corporation should downgrade the Common Shares or change their opinion of the Corporation's business prospects or report inaccurate information, the Common Share price may decline. If one or more of these analysts cease coverage of the Corporation or fail to publish reports on the Corporation regularly, demand for the Common Shares could decrease, which may cause the price and trading volume of the Common Shares to decline.

5. DIVIDENDS

5.1 Common Shares

The amount of dividends declared for each Common Share for fiscal 2017, 2018 and 2019 were $0.47, $0.50 and $0.55, respectively.

APUC follows a quarterly dividend schedule, subject to subsequent Board declarations each quarter. APUC's current quarterly dividend to shareholders is $0.1410 per Common Share or $0.5640 per Common Share per annum.

The Board has adopted a dividend policy to provide sustainable dividends to shareholders, considering cash flow from operations, financial condition, financial leverage, working capital requirements and investment opportunities. The Board can modify the dividend policy from time to time at its discretion. There are no restrictions on the dividend policy of APUC. The amount of dividends declared and paid is ultimately dependent on a number of factors, including the risk factors previously noted, and there is no assurance as to the amount or timing of such dividends in the future. See "Enterprise Risk Factors".

5.2 Preferred Shares

On November 9, 2012, APUC issued 4,800,000 cumulative rate reset Series A preferred shares (the "**Series A Shares**"). Holders of Series A Shares are entitled to receive fixed cumulative preferential cash dividends, as and when declared by the Board, payable quarterly on the last business day of March, June, September and December in each year. In each of 2017 and 2018, dividends were paid at an annual rate equal to C$1.1250 per Series A Share. In 2019, dividends were paid at an annual rate equal to C$1.2905 per Series A Share. For the current five-year period from December 31, 2018 to December 31, 2023, the annual rate of the dividends is equal to C$1.2905 per Series A Share.

On January 1, 2013, the Corporation issued 100 Series C preferred shares (the "**Series C Shares**") and exchanged such shares for the 100 Class B units of St. Leon LP, including 36 units held indirectly by certain members of APUC's senior management. The Series C Shares provide dividends essentially identical to those expected from the Class B units. In 2017, 2018 and 2019, dividends paid to holders of Series C Shares were C$10,389, C$8,866 and C$12,361, respectively, per Series C Share.

On March 5, 2014, APUC issued 4,000,000 cumulative rate reset Series D preferred shares (the "**Series D Shares**"). Holders of Series D Shares are entitled to receive fixed cumulative preferential cash dividends, as and when declared by the Board, payable quarterly on the last business day of March, June, September and December in each year. In 2017 and 2018, dividends were paid at an annual rate of C$1.250 per Series D Share. In 2019, dividends were paid at an annual rate equal to C$1.2671 per Series D Share. For the current five-year period from March 31, 2019 to March 31, 2024, the annual rate of the dividends is equal to C$1.2728 per Series D Share.

5.3 Dividend Reinvestment Plan

Under APUC's shareholder dividend reinvestment plan (the "**Reinvestment Plan**"), holders of Common Shares who reside in Canada or the United States may opt to reinvest the cash dividends paid on their Common Shares in additional Common Shares which, at APUC's election, will either be purchased on the open market or newly issued from treasury. Common Shares purchased under the Reinvestment Plan are currently being issued from treasury at a 5% discount to the prevailing market price (as determined in accordance with the terms of the Reinvestment Plan). The 5% discount will remain in effect for all cash dividends that may be declared, if any, by the Board until otherwise announced, at its discretion.

6. DESCRIPTION OF CAPITAL STRUCTURE

6.1 Common Shares

The Common Shares are publicly traded on the TSX and the NYSE under the ticker symbol "AQN". As at December 31, 2019, APUC had 524,223,323 issued and outstanding Common Shares.

APUC may issue an unlimited number of Common Shares. The holders of Common Shares are entitled to dividends, if and when declared; to one vote for each share at meetings of the holders of Common Shares; and to receive a pro rata share of any remaining property and assets of APUC upon liquidation, dissolution or winding up of APUC. All shares are of the same class and with equal rights and privileges and are not subject to future calls or assessments.

6.2 Preferred Shares

APUC is also authorized to issue an unlimited number of preferred shares, issuable in one or more series, containing terms and conditions as approved by the Board. As at December 31, 2019, APUC had outstanding:

- 4,800,000 Series A Shares, yielding 5.162% annually for the five-year period ending on December 31, 2023;
- 100 Series C Shares; and
- 4,000,000 Series D Shares, yielding 5.091% annually for the five-year period ending on March 31, 2024.

As at December 31, 2019, no Series B Shares, Series E Shares, Series F Shares or Series G Shares were outstanding.

Series A Shares

The Series A Shares rank senior to the Common Shares and rank on parity with every other series of preferred shares as to dividends, may be redeemed by APUC on December 31, 2023 and every five years thereafter and are convertible upon the occurrence of certain events into cumulative floating rate preferred shares, Series B (the "**Series B Shares**"). The Series A Shares were redeemable by APUC on December 31, 2018 (the "**Series A Shares Redemption Right**"), but APUC elected not to exercise its redemption right. The Series A Shares rank on parity with the preferred shares of every other series and senior to the Common Shares upon liquidation, dissolution or winding up of APUC. The Series A Shares are entitled to receive C$25.00 per Series A Share plus all accrued and unpaid dividends thereon, but are not entitled to share in any further distribution of the assets of APUC.

Series B Shares

APUC is authorized to issue up to 4,800,000 Series B Shares upon the conversion of Series A Shares upon the occurrence of certain events. The Series B Shares rank senior to the Common Shares and rank on parity with every other series of preferred shares as to dividends, may be redeemed by APUC on any Series B Conversion Date (as defined in the articles of APUC), and are convertible into Series A Shares upon the occurrence of certain events. The Series B Shares rank on parity with the preferred shares of every other series and senior to the Common Shares upon liquidation, dissolution or winding up of APUC. The Series B Shares are entitled to receive C$25.00 per Series B Share plus all accrued and unpaid dividends thereon, but are not entitled to share in any further distribution of the assets of APUC. Upon APUC's election not to exercise the Series A Shares Redemption Right, the holders of the Series A Shares had the right to convert all or part of their Series A Shares into Series B Shares on December 31, 2018. However, since less than the required minimum of 1,000,000 Series A

Shares were tendered for conversion, none of the Class A Shares were converted into Class B Shares and no Class B Shares have been issued by APUC.

Series C Shares

The Series C Shares rank senior to the Common Shares and rank on parity with every other series of preferred shares as to dividends and are entitled to cumulative dividends in accordance with the formula set forth in the articles of APUC. The Series C Shares rank on parity with the preferred shares of every other series and senior to the Common Shares upon liquidation, dissolution or winding up of APUC. The Series C Shares are entitled to receive the redemption price calculated in accordance with the share terms plus all accrued and unpaid dividends thereon, but are not entitled to share in any further distribution of the assets of APUC. The Series C Shares are redeemable upon the occurrence of certain events. During the period between May 20, 2031 and June 19, 2031, the Series C Shares are convertible into Common Shares and, if not so converted, will be automatically redeemed on June 19, 2031. Holders of the Series C Shares include a partnership controlled by Ian Robertson, Chief Executive Officer of the Corporation and a partnership controlled by Chris Jarratt, Vice Chair of the Corporation.

Series D Shares

The Series D Shares rank senior to the Common Shares and rank on parity with every other series of preferred shares as to dividends, may be redeemed by APUC on March 31, 2024 and every five years thereafter, and are convertible upon the occurrence of certain events into cumulative floating rate preferred shares, Series E (the "**Series E Shares**"). The Series D Shares were redeemable by APUC on April 1, 2019 (the "**Series D Shares Redemption Right**"), but APUC elected not to exercise its redemption right. The Series D Shares rank on parity with the preferred shares of every other series and senior to the Common Shares upon liquidation, dissolution or winding up of APUC. The Series D Shares are entitled to receive C $25.00 per Series D Share plus all accrued and unpaid dividends thereon, but are not entitled to share in any further distribution of the assets of APUC.

Series E Shares

APUC is authorized to issue up to 4,000,000 Series E Shares upon the conversion of Series D Shares upon the occurrence of certain events. The Series E Shares rank senior to the Common Shares and rank on parity with every other series of preferred shares as to dividends, may be redeemed by APUC on any Series E Conversion Date (as defined in the articles of APUC), and are convertible into Series D Shares upon the occurrence of certain events. The Series E Shares rank on parity with the preferred shares of every other series and senior to the Common Shares upon liquidation, dissolution or winding up of APUC. The Series E Shares are entitled to receive C$25.00 per Series E Share plus all accrued and unpaid dividends thereon, but are not entitled to share in any further distribution of the assets of APUC. Upon APUC's election not to exercise the Series D Shares Redemption Right, the holders of the Series D Shares had the right to convert all or part of their Series D Shares into Series E Shares on April 1, 2019. However, since less than the required minimum of 1,000,000 Series D Shares were tendered for conversion, none of the Class D Shares were converted into Class E Shares and no Class E Shares have been issued by APUC.

Series F Shares

APUC is authorized to issue an unlimited number of Series F Shares following the conversion of the 2018 Subordinated Notes upon the occurrence of certain bankruptcy-related events. The Series F Shares rank senior to the Common Shares and rank on parity with every other series of preferred shares as to dividends and may be redeemed by APUC, subject to certain restrictions, at any time after October 17, 2023. The Series F Shares rank on parity with the preferred shares of every other series and senior to the Common Shares upon liquidation, dissolution or winding up of APUC. The Series F Shares are entitled to receive C$25.00 per Series F Share plus all accrued and unpaid dividends thereon, but are not entitled to share in any further distribution of the assets of APUC.

Series G Shares

APUC is authorized to issue an unlimited number of Series G Shares following the conversion of the 2019 Subordinated Notes upon the occurrence of certain bankruptcy-related events. The Series G Shares rank senior to the Common Shares and rank on parity with every other series of preferred shares as to dividends and may be redeemed by APUC, subject to certain restrictions, at any time after July 1, 2024. The Series G Shares rank on parity with the preferred shares of every other series and senior to the Common Shares upon liquidation, dissolution or winding up of APUC. The Series G Shares are entitled to receive C$25.00 per Series G Share plus all accrued and unpaid dividends thereon, but are not entitled to share in any further distribution of the assets of APUC.

Subject to applicable corporate law, the outstanding preferred shares are non-voting and not entitled to receive notice of any meeting of shareholders, except that the Series A Shares (and the Series B Shares into which they are convertible) and Series D Shares (and Series E Shares into which they are convertible), the Series F Shares and the Series G Shares will be entitled to one vote per share if APUC shall have failed to pay eight quarterly dividends on such shares.

6.3 Subordinated Notes

2018 Subordinated Notes

On October 17, 2018, APUC completed the sale of $287.5 million aggregate principal amount of 2018 Subordinated Notes. The 2018 Subordinated Notes are publicly traded on the NYSE under the ticker symbol "AQNA".

The Corporation will pay interest on the 2018 Subordinated Notes at a fixed rate of 6.875% per year in equal quarterly installments until October 17, 2023. Starting on October 17, 2023, and quarterly on every January 17, April 17, July 17 and October 17 of each year during which the 2018 Subordinated Notes are outstanding thereafter until October 17, 2078 (each such date, a "**2018 Notes Interest Reset Date"**), the interest rate on the 2018 Subordinated Notes will be reset to an interest rate per annum equal to (i) starting on October 17, 2023, on every 2018 Notes Interest Reset Date until October 17, 2028, the three month LIBOR plus 3.677%, payable in arrears, (ii) starting on October 17, 2028, on every 2018 Notes Interest Reset Date until October 17, 2043, the three month LIBOR plus 3.927%, payable in arrears, and (iii) starting on October 17, 2043, on every 2018 Notes Interest Reset Date until October 17, 2078, the three month LIBOR plus 4.677%, payable in arrears. So long as no event of default has occurred and is continuing, APUC may elect to defer the interest payable on the 2018 Subordinated Notes on one or more occasions for up to five consecutive years.

The 2018 Subordinated Notes have a maturity date of October 17, 2078. On or after October 17, 2023, APUC may, at its option, redeem the 2018 Subordinated Notes at a redemption price equal to 100% of the principal amount thereof, together with accrued and unpaid interest.

Upon the occurrence of certain bankruptcy-related events in respect of APUC, the 2018 Subordinated Notes automatically convert into Series F Shares.

2019 Subordinated Notes

On May 23, 2019, APUC completed the sale of $350 million aggregate principal amount of 2019 Subordinated Notes. The 2019 Subordinated Notes are publicly traded on the NYSE under the ticker symbol "AQNB".

The Corporation will pay interest on the 2019 Subordinated Notes at a fixed rate of 6.2% per year in equal quarterly installments until July 1, 2024. Starting on July 1, 2024, and quarterly on every January 1, April 1, July 1 and October 1 of each year during which the 2019 Subordinated Notes are outstanding thereafter until July 1, 2079 (each such date, a "**2019 Notes Interest Reset Date"**), the interest rate on the 2019 Subordinated Notes will be reset to an interest rate per annum equal to (i) starting on July 1, 2024, on every 2019 Notes Interest Reset Date until July 1, 2029, the three month LIBOR plus 4.01%, payable in arrears, (ii) starting on July 1, 2029, on every 2019 Notes Interest Reset Date until July 1, 2049, the three month LIBOR plus 4.26%, payable in arrears, and (iii) starting on July 1, 2049, on every 2019 Notes Interest Reset Date until July 1, 2079, the three month LIBOR plus 5.01%, payable in arrears. So long as no event of default has occurred and is continuing, APUC may elect to defer the interest payable on the 2019 Subordinated Notes on one or more occasions for up to five consecutive years. Concurrent with the offering of the 2019 Subordinated Notes, APUC entered into a cross currency swap to convert the U.S. dollar denominated proceeds from the offering into Canadian dollars, resulting in an effective interest rate to APUC throughout the fixed-rate period of the 2019 Subordinated Notes of approximately 5.96%.

The 2019 Subordinated Notes have a maturity date of July 1, 2079. On or after July 1, 2024, APUC may, at its option, redeem the 2019 Subordinated Notes at a redemption price equal to 100% of the principal amount thereof, together with accrued and unpaid interest.

Upon the occurrence of certain bankruptcy-related events in respect of APUC, the 2019 Subordinated Notes automatically convert into Series G Shares.

6.4 Shareholders' Rights Plan

The shareholders' rights plan, as amended and restated in 2019 (the "**Amended and Restated Rights Plan**") is designed to ensure the fair treatment of shareholders in any transaction involving a potential change of control of APUC and will provide the Board and shareholders with adequate time to evaluate any unsolicited take-over bid and, if appropriate, to seek out alternatives to maximize shareholder value.

Until the occurrence of certain specific events, the rights will trade with the Common Shares and be represented by certificates representing the Common Shares. The rights become exercisable only when a person, including any party related to it or acting jointly with it (subject to certain exceptions), acquires or announces its intention to acquire 20% or more of the outstanding Common Shares without complying with the permitted bid provisions of the Amended and Restated Rights Plan. Should a non-permitted bid be launched, each right would entitle each holder of shares (other than the acquiring person and persons related to it or acting jointly with it) to purchase additional Common Shares at a 50% discount to the market price at the time.

It is not the intention of the Amended and Restated Rights Plan to prevent take-over bids but to ensure their proper evaluation by the market. Under the Amended and Restated Rights Plan, a permitted bid is a bid made to all shareholders for all of their Common Shares on identical terms and conditions that is open for no less than 105 days. If at the end of 105 days at least 50% of the outstanding Common Shares, other than those owned by the offeror and certain related parties, have been tendered and not withdrawn, the offeror may take up and pay for the Common Shares but must extend the bid for a further 10 days to allow all other shareholders to tender.

The Amended and Restated Rights Plan will remain in effect until the termination of the annual meeting of the shareholders of APUC in 2022 (unless extended by approval of the shareholders at such meeting) or its termination under the terms of the Amended and Restated Rights Plan.

7. MARKET FOR SECURITIES

7.1 Trading Price and Volume

7.1.1 Common Shares

The Common Shares are listed and posted for trading on the TSX and NYSE under the symbol "AQN". The following table sets forth the high and low trading prices and the aggregate volumes of trading of the Common Shares for the periods indicated (as quoted by the TSX and NYSE).

		TSX			NYSE	
2019	**High (C$)**	**Low (C$)**	**Volume**	**High ($)**	**Low ($)**	**Volume**
January	14.58	13.38	22,741,443	11.09	9.91	1,404,432
February	14.86	14.18	21,483,130	11.18	10.65	1,421,050
March	15.29	14.62	31,047,577	11.41	11.02	1,668,365
April	15.46	14.83	19,707,638	11.60	11.11	1,647,943
May	15.98	15.00	22,747,144	11.86	11.15	2,256,814
June	16.60	15.69	21,626,090	12.54	11.63	2,066,398
July	16.65	15.80	20,423,588	12.67	12.03	1,582,660
August	17.45	16.46	23,273,118	13.10	12.44	1,774,196
September	18.47	17.19	22,881,613	13.92	13.04	1,882,789
October	18.80	17.43	43,404,626	14.12	13.02	5,886,721
November	18.67	17.55	62,281,527	14.04	13.32	2,824,024
December	19.34	18.25	41,206,121	14.60	13.91	2,086,660

7.1.2 Preferred Shares

Series A Shares

The Series A Shares are listed and posted for trading on the TSX under the symbol "AQN.PR.A". The following table sets forth the high and low trading prices and the aggregate volume of trading of the Series A Shares for the periods indicated (as quoted by the TSX).

2019	High (C$)	Low (C$)	Volume
January	20.60	19.45	74,421
February	19.90	18.99	91,502
March	20.64	19.85	40,426
April	20.55	19.94	37,066
May	20.02	19.25	48,914
June	19.90	18.24	58,313
July	19.34	18.46	235,810
August	19.35	17.68	154,454
September	18.63	17.90	109,202
October	18.50	18.11	135,831
November	18.97	18.36	64,232
December	19.60	18.60	118,897

Series D Shares

The Series D Shares are listed and posted for trading on the TSX under the symbol "AQN.PR.D". The following table sets forth the high and low trading prices and the aggregate volume of trading of the Series D Shares for the periods indicated (as quoted by the TSX).

2019	High (C$)	Low (C$)	Volume
January	22.65	20.69	46,510
February	21.10	20.38	23,362
March	21.73	21.00	42,002
April	21.57	21.25	73,180
May	21.51	21.05	43,047
June	21.13	20.49	76,600
July	20.97	20.45	21,258
August	20.80	19.50	40,853
September	20.37	19.51	70,898
October	20.10	19.18	153,932
November	19.76	19.01	379,416
December	20.50	19.30	218,047

7.1.3 Subordinated Notes

2018 Subordinated Notes

The 2018 Subordinated Notes are listed and posted for trading on the NYSE under the symbol "AQNA". The following table sets forth the high and low trading prices and the aggregate volume of trading of the 2018 Subordinated Notes for the periods indicated (as quoted by the NYSE).

2019	High ($)	Low ($)	Volume ($)
January	26.74	24.41	921,313
February	26.47	25.65	633,835
March	27.25	26.06	799,526
April	27.00	26.25	622,508
May	26.78	26.30	1,810,163
June	26.91	26.31	408,393
July	27.80	26.42	466,086
August	27.97	27.40	609,668
September	28.09	27.12	1,801,748
October	28.78	27.18	653,045
November	28.04	27.40	368,180
December	28.63	26.90	354,229

2019 Subordinated Notes

The 2019 Subordinated Notes are listed and posted for trading on the NYSE under the symbol "AQNB". The following table sets forth the high and low trading prices and the aggregate volume of trading of the 2019 Subordinated Notes for the periods indicated (as quoted by the NYSE).

2019	High ($)	Low ($)	Volume ($)
May (beginning May 28)	25.85	25.35	1,931,303
June	25.78	25.38	3,810,178
July	26.87	25.63	1,479,272
August	27.86	26.42	466,666
September	27.94	26.21	509,798
October	28.24	27.20	663,936
November	28.14	27.35	568,399
December	28.50	26.67	406,841

7.2 Prior Sales

During the year ended December 31, 2019, there were no issuances or sales of any class of APUC securities that are outstanding but not listed or quoted on a marketplace.

7.3 Escrowed Securities and Securities Subject to Contractual Restrictions on Transfer

There are no securities of APUC that are, to APUC's knowledge, held in escrow or subject to contractual restrictions on transfer as of the date of this AIF.

8. DIRECTORS AND OFFICERS

8.1 Name, Occupation and Security Holdings

The following table sets forth certain information with respect to the directors and executive officers of APUC as of the date of this AIF, and information on their history with the Corporation.

Name and Place of Residence	Principal Occupation	Served as Director or Officer of APUC from
CHRISTOPHER J. BALL Toronto, Ontario, Canada	Christopher Ball is the Executive Vice President of Corpfinance International Limited, and President of CFI Capital Inc., both of which are boutique investment banking firms. From 1982 to 1988, Mr. Ball was Vice President at Standard Chartered Bank of Canada with responsibilities for the Canadian branch operation. Prior to that, Mr. Ball held various managerial positions with the Canadian Imperial Bank of Commerce. He is also a member of the Hydrovision International Advisory Board, was a director of Clean Energy BC, is a director of First Nations Power Authority and is a recipient of the Clean Energy BC Lifetime Achievement Award. Mr. Ball is a holder of the Institute of Corporate Directors Director designation.	Director of APUC since October 27, 2009 Trustee of APCo from October 22, 2002 until May 12, 2011
ARUN BANSKOTA Houston, Texas, USA	Arun Banskota is the President of APUC. Prior to that, as Vice President, Data Center Global Services and Energy Team at Amazon.com, Mr. Banskota was responsible for the planning, engineering, and delivery of datacenter capacity for Amazon Web Services, a high growth global market-leader of cloud services. Mr. Banskota previously served as President and CEO of EVGo, a high growth start-up division of NRG created to build scale and presence in the emerging electrical vehicle sector. Mr. Banskota was also Managing Director, Global Power, El Paso Corporation. He was also on the leadership team for a large-scale solar power company and has successfully managed project development and financing for solar, wind, and natural gas projects.	Officer of APUC since February 10, 2020
DAVID BRONICHESKI Oakville, Ontario, Canada	Mr. Bronicheski is the Chief Financial Officer of APUC. He has held various senior management positions including Executive Vice President and CFO of a publicly traded income trust providing local telephone, cable television and internet service. He was also CFO for a large public hospital in Ontario. Mr. Bronicheski holds a Bachelor of Arts in economics (cum laude), a Bachelor of Commerce degree and an MBA (University of Toronto, Rotman School of Management). He is also a Chartered Accountant and a Chartered Professional Accountant.	Officer of APUC since October 27, 2009 Officer of APCo since September 17, 2007
CHRIS HUSKILSON Wellington, Nova Scotia, Canada	Christopher Huskilson was the President and Chief Executive Officer of Emera Inc., from 2004-2018. Since leaving Emera Inc., Mr. Huskilson has been involved in supporting the start-up ecosystem emerging in Atlantic Canada. Mr. Huskilson is a founding partner and active mentor in Creative Destruction Lab (CDL - Atlantic) which is an objectives-based program for scalable, seed-stage science- and technology-based companies. Mr. Huskilson is also a founding member of Canada's Ocean Supercluster and has invested in a number of innovation based start-up companies. He has also served as a member on the boards of a number of public and private companies in Canada and internationally. Mr. Huskilson holds a Bachelor of Science in Engineering and a Master of Science in Engineering from the University of New Brunswick.	Director of APUC from October 27, 2009 to June 8, 2017, and since January 2, 2020 Trustee of APCo from July 20, 2009 until May 12, 2011
CHRISTOPHER K. JARRATT Oakville, Ontario, Canada	Christopher Jarratt has over 25 years of experience in the independent electric power and utility sectors and is Vice Chair of APUC. Mr. Jarratt is a founder and principal of APCI, a private independent power developer formed in 1988 which is the predecessor organization to APCo and APUC. Between 1997 and 2009, Mr. Jarratt was a principal in Algonquin Power Management Inc. which managed APCo (formerly Algonquin Power Income Fund). Since 2009, Mr. Jarratt has been a Board member and served as Vice Chair of APUC. Prior to 1988, Mr. Jarratt was a founder and principal of a consulting firm specializing in renewable energy project development and environmental approvals. Mr. Jarratt earned an Honours Bachelor of Science degree from the University of Guelph in 1981 specializing in water resources engineering and holds an Ontario Professional Engineering designation. Additionally, Mr. Jarratt holds a Chartered Director certification from the Directors College (McMaster University). Mr. Jarratt was co-recipient of the 2007 Ernst & Young Entrepreneur of the Year finalist award.	Director and Officer of APUC since October 27, 2009 Officer of APCo since June 22, 2011

Name and Place of Residence	Principal Occupation	Served as Director or Officer of APUC from
ANTHONY (JOHNNY) JOHNSTON Toronto, Ontario, Canada	Johnny Johnston is the Chief Operating Officer of APUC. Mr. Johnston has over 20 years of international experience in the utilities industry. Prior to joining the Corporation, Mr. Johnston, worked for National Grid where he led the transformation of its U.S. gas business. He has held a number of senior leadership roles in operations, customer service and strategy working in both the U.K. and U.S. across gas and electric businesses. Mr. Johnston has served on the board of the not-for-profit Heartshare Human Services of New York. Mr. Johnston holds a Masters degree in Engineering Science from the University of Oxford and a Master of Business Administration degree from the University of Cranfield. Mr. Johnston is a registered Chartered Engineer in the U.K.	Officer of APUC since January 8, 2019
D. RANDY LANEY Farmington, Arkansas, USA	D. Randy Laney was most recently Chairman of the board of directors of Empire from 2009 until APUC's acquisition of Empire on January 1, 2017. He joined the board of Empire in 2003 and served as the Non-Executive Vice Chairman from 2008 to 2009. Mr. Laney, semi-retired since 2008, has held numerous senior level positions with both public and private companies during his career, including 23 years with Wal-Mart Stores, Inc. in various executive positions such as Vice President of Finance, Benefits and Risk Management and Vice President of Finance and Treasurer. In addition, Mr. Laney has provided strategic advisory services to both private and public companies and served on numerous profit and non-profit boards. Mr. Laney brings significant management and capital markets experience, and strategic and operational understanding to his position on the Board. Mr. Laney holds a Bachelor of Science and a Juris Doctor from the University of Arkansas.	Director of APUC since February 1, 2017
KENNETH MOORE Toronto, Ontario, Canada	Kenneth Moore is the Managing Partner of NewPoint Capital Partners Inc., an investment banking firm. From 1993 to 1997, Mr. Moore was a senior partner at Crosbie & Co., a Toronto mid-market investment banking firm. Prior to investment banking, he was a Vice-President at Barclays Bank where he was responsible for a number of leveraged acquisitions and restructurings. Mr. Moore holds a Chartered Financial Analyst designation. Additionally, he holds a Chartered Director certification from the Directors College (McMaster University).	Director of APUC since October 27, 2009 Trustee of APCo from November 12, 1998 until November 10, 2010
JEFF NORMAN Burlington, Ontario, Canada	Jeff Norman is the Chief Development Officer of APUC, serving in this role since 2008. He was appointed to the APUC executive team in 2015. Mr. Norman co-founded the Algonquin Power Venture Fund in 2003 and served as President until it was acquired by APCo in 2008. Mr. Norman holds a Bachelor of Arts (Chartered Accountancy) and a Masters of Accounting from the University of Waterloo.	Officer of APUC since May 25, 2015
KIRSTEN OLSEN Toronto, Ontario Canada	Kirsten Olsen joined APUC in November 2019 as Chief Human Resources Officer. Ms. Olsen has 20 years of international HR experience with expertise in supporting large-scale change, talent management and M&A. Prior to joining APUC, Kirsten held progressive HR leadership roles over the course of 12 years with GE in the UK. Ms. Olsen holds a Master of Industrial Relations & Human Resources from the University of Toronto and an Honours Bachelor of Arts with Distinction in Psychology from Huron College at the University of Western Ontario.	Officer of APUC since January 2, 2020
MARY ELLEN PARAVALOS Oakville, Ontario, Canada	Mary Ellen Paravalos is the Chief Compliance and Risk Officer of APUC. Ms. Paravalos has over 20 years of international experience in the energy industry across operating, strategy and regulation & compliance areas. Prior to joining APUC, Ms. Paravalos was Vice President, ISO, Siting, and Compliance at Eversource Energy, and prior to that held a number of leadership roles at National Grid. Ms. Paravalos has served as a Director and President for the not-for-profit company New England Women in Energy and Environment. Ms. Paravalos holds a Masters degree in electric power engineering from Rensselaer Polytechnic Institute and a Bachelor's degree in electrical engineering from Northeastern University. Ms Paravalos is a registered engineer in the state of Massachusetts.	Officer of APUC since October 9, 2018

Name and Place of Residence	Principal Occupation	Served as Director or Officer of APUC from
IAN E. ROBERTSON Oakville, Ontario, Canada	Ian Robertson is the Chief Executive Officer of APUC. Mr. Robertson is a founder and principal of APCI, a private independent power developer formed in 1988 which was a predecessor organization to APUC. Mr. Robertson has almost 30 years of experience in the development of electric power generating projects and the operation of diversified regulated utilities. Mr. Robertson is an electrical engineer and holds a Professional Engineering designation through his Bachelor of Applied Science degree awarded by the University of Waterloo. Mr. Robertson earned a Master of Business Administration degree from York University and holds a Chartered Financial Analyst designation. Additionally, he holds a Chartered Director certification from the Directors College (McMaster University), as well as a Global Professional Master of Laws degree from the University of Toronto. Commencing in 2013, Mr. Robertson has served on the Board of Directors of the American Gas Association.	Director and Officer of APUC since October 27, 2009 Trustee of APCo since May 12, 2011 Officer of APCo since June 22, 2011
MASHEED SAIDI Dana Point, California, United States	Masheed Saidi has over 30 years of operational and business leadership experience in the electric utility industry. Between 2010 and 2017, Ms. Saidi was an Executive Consultant of Energy Initiatives Group, a specialized group of experienced professionals that provide technical, commercial and business consulting services to utilities, ISOs, government agencies and other organizations in the energy industry. Between 2005 and 2010, Ms. Saidi was the Chief Operating Officer and Executive Vice President of U.S. Transmission for National Grid USA, for which she was responsible for all aspects of the U.S. transmission business. Ms. Saidi previously served as Chairperson of the board of directors for the non-profit organization Mary’s Shelter, and also previously served on the board of directors of the Northeast Energy and Commerce Association. She earned her Bachelors in Power System Engineering from Northeastern University and her Masters of Electrical Engineering from the Massachusetts Institute of Technology. She is a Registered Professional Engineer in the state of Massachusetts.	Director of APUC since June 18, 2014
DILEK SAMIL Las Vegas, Nevada, United States	Dilek Samil has over 30 years of finance, operations and business experience in both the regulated energy utility sector as well as wholesale power production. Ms. Samil joined NV Energy as Chief Financial Officer and retired as Executive Vice President and Chief Operating Officer. While at NV Energy, Ms. Samil completed the financial transformation of the company, bringing its financial metrics in line with those of the industry. As Chief Operating Officer, Ms. Samil focused on enhancing the company’s safety and customer care culture. Prior to her role at NV Energy, Ms. Samil gained considerable experience in generation and system operations as President and Chief Operating Officer for CLECO Power. During her tenure at CLECO, the company completed construction of its largest generating unit and successfully completed its first rate case in over 10 years. Ms. Samil also served as CLECO’s Chief Financial Officer at a time when the industry and the company faced significant turmoil in the wholesale markets. She led the company’s efforts in the restructuring of its wholesale and power trading activities. Prior to NV Energy and CLECO, Ms. Samil spent about 20 years at NextEra where she held positions of increasing responsibility, primarily in the finance area. Ms. Samil holds a Bachelor of Science from the City College of New York and a Masters of Business Administration from the University of Florida.	Director of APUC since October 1, 2014
MELISSA STAPLETON BARNES Carmel, Indiana, United States	Melissa Stapleton Barnes has been Senior Vice President, Enterprise Risk Management, and Chief Ethics and Compliance Officer for Eli Lilly and Company since January 2013. In this role, she is an executive officer and serves as a member of the company’s executive committee. She previously held the role of Vice President, Deputy General Counsel from 2012 to 2013; and General Counsel, Lilly Diabetes and Lilly Oncology and Senior Director and Assistant General Counsel from 2010 - 2012. She holds a Bachelor of Science in Political Science & Government (highest distinction) from Purdue University and a Juris Doctorate from Harvard Law School. Ms. Barnes is a member of several professional organizations including the Ethics and Compliance Initiative, Ethisphere – Business Ethics Leadership Alliance; CEB, Corporate Ethics Leadership Council; Healthcare Businesswomen's Association; and is a licensed attorney with the Indiana State Bar. Other board positions include The Center for the Performing Arts (Chair), The Great American Songbook Foundation and Ethics Resource Center.	Director of APUC since June 9, 2016

Name and Place of Residence	Principal Occupation	Served as Director or Officer of APUC from
GEORGE L. STEEVES Aurora, Ontario, Canada	George Steeves has been Senior Project Manager of True North Energy, an energy consulting firm specializing in the provision of technical and financial due diligence services for renewable energy projects, since July 2017. From April 2002 to July 2017, Mr. Steeves was principal of True North Energy. From January 2001 to April 2002, Mr. Steeves was a division manager of Earthtech Canada Inc. Prior to January 2001, he was the President of Cumming Cockburn Limited, an engineering firm, and has extensive financial expertise in acting as a chair, director and/or audit committee member of public and private companies, including the Corporation, and formerly Borealis Hydroelectric Holdings Inc. and KMS Power Income Fund. Mr. Steeves received a Bachelor and Masters of Engineering from Carleton University and holds a Professional Engineering designation in Ontario and British Columbia. Additionally, he holds a Chartered Director certification from the Directors College (McMaster University).	Director of APUC since October 27, 2009 Trustee of APCo from September 8, 1997 until May 12, 2011
JENNIFER TINDALE Campbellville, Ontario, Canada	Jennifer Tindale is the Chief Legal Officer of APUC. Ms. Tindale has over 20 years of experience advising public companies on acquisitions, dispositions, mergers, financings, corporate governance and disclosure matters. From July 2011 to February 2017, Ms. Tindale was the Executive Vice President, General Counsel & Secretary at a cross-listed real estate investment trust. Prior to that, she was Vice President, Associate General Counsel & Corporate Secretary at a public Canadian-based pharmaceutical company and before that she was a partner at a top tier Toronto law firm, practising corporate securities law. Ms. Tindale holds a Bachelor of Arts and a Bachelor of Laws from the University of Western Ontario.	Officer of APUC since February 7, 2017
GEORGE TRISIC Oakville, Ontario, Canada	George Trisic is the Chief Governance Officer and Corporate Secretary of APUC. He has broad experience managing in high growth, start up and expanding businesses across multiple sites and regions. In his role, Mr. Trisic is responsible for the governance, sustainability and corporate secretarial functions of the Corporation. His skill set includes leading multi-functional groups in finance, human resources, legal and information technology in a senior role. Mr. Trisic holds a Bachelor of Laws Degree from the University of Western Ontario. Additionally, he holds a Chartered Director certification from the Directors College (McMaster University).	Officer of APUC since November 4, 2013

Each director will serve as a director of APUC until the next annual meeting of shareholders or until his or her successor is elected in accordance with the by-laws of APUC.

To the knowledge of the Corporation, as at February 26, 2019, the directors and executive officers of APUC, as a group, beneficially owned, directly or indirectly, or exercised control or direction over 2,622,349 Common Shares, representing less than 1% of the total number of issued and outstanding Common Shares before giving effect to the exercise of options to purchase Common Shares held by such directors and executive officers.

8.2 Audit Committee

Under the by-laws of APUC, the directors may appoint from their number, committees to effect the administration of the director's duties. The directors have established an Audit Committee currently comprised of five directors of APUC: Mr. Ball (Chair), Ms. Stapleton Barnes, Mr. Huskilson, Mr. Laney and Ms. Samil, all of whom are independent and financially literate for purposes of National Instrument 52-110 - *Audit Committees*. The Audit Committee is responsible for reviewing significant accounting, reporting and internal control matters, reviewing all published quarterly and annual financial statements and recommending their approval to the Directors and assessing the performance of APUC's auditors.

8.2.1 Audit Committee Charter

The Audit Committee mandate is attached as Schedule A to this AIF.

8.2.2 Relevant Education and Experience

The following is a description of the education and experience, apart from their roles as directors of APUC, of each member of the Audit Committee that is relevant to the performance of their responsibilities as a member of the Audit Committee.

Mr. Ball's financial experience includes over 30 years of domestic and international lending experience. He is Executive Vice-President of Corpfinance International Limited, a privately owned long-term debt and securitization financier. Mr. Ball was formerly a Vice-President at Standard Chartered Bank of Canada with responsibilities for the Canadian branch operation.

Prior to that, Mr. Ball held numerous positions with Canadian Imperial Bank of Commerce, including credit function responsibilities. Mr. Ball is the Chair of the Audit Committee.

Mr. Huskilson's financial experience includes over 35 years in leadership and operational roles in the regulated utilities business in Canada, the United States and the Caribbean. Mr. Huskilson was President and Chief Executive Officer of Emera Inc., from 2004 to 2018. Prior to that Mr. Huskilson held a number of positions within Nova Scotia Power Inc. and its predecessor, Nova Scotia Power Corporation, since June 1980. Mr. Huskilson holds a Bachelor of Science in Engineering and a Master of Science in Engineering from the University of New Brunswick.

Mr. Laney's financial experience includes a number of senior executive roles with Wal-Mart Stores, Inc. including roles as Vice President, Finance and Treasurer and as Vice President Finance, Benefits and Risk Management. Mr. Laney also served as a member of the Empire board of directors commencing in 2003 and acted as Chair of the Empire board from 2009 until APUC's acquisition of Empire on January 1, 2017. Mr. Laney was also a member of the Audit Committee of Empire from May 2003 to April 2005.

Ms. Samil has extensive financial experience, with over 30 years of finance, operations and business experience in the regulated energy utility sector. During her career, Ms. Samil was the Executive Vice President and Chief Operating Officer of NV Energy and gained considerable experience in generation and system operations as President and Chief Operating Officer for CLECO Power LLC. Ms. Samil holds a Bachelor of Science from the City College of New York and a Masters of Business Administration from the University of Florida.

Ms. Stapleton Barnes' financial experience includes a number of risk management and legal/regulatory senior executive roles in a public company. Ms. Stapleton Barnes is currently an executive officer and a member of the corporate executive committee of Eli-Lilly and Company. She has extensive experience in the areas of risk management, legal and regulatory and is a licensed attorney with the Indiana State Bar.

8.2.3 Pre-Approval Policies and Procedures

The Audit Committee has established a policy requiring pre-approval by the Audit Committee of all audit and permitted non-audit services provided to APUC by its external auditor. The Audit Committee may delegate pre-approval authority to a member of the Audit Committee; however, the decisions of any member of the Audit Committee to whom this authority has been delegated must be presented to the full Audit Committee at its next scheduled Audit Committee meeting.

Services	2019 Fees (C$)	2018 Fees (C$)
Audit Fees[1]	4,432,950	4,245,342
Audit-Related Fees[2]	135,500	85,500
Tax Fees[3]	815,455	494,448
All Other Fees[4]	5,800	Nil

1 For professional services rendered for audit or review or services in connection with statutory or regulatory filings or engagements.
2 For assurance and related services that are reasonably related to the performance of the audit or review of APUC's financial statements and not reported under Audit Fees, including audit procedures related to regulatory commission filings.
3 For tax advisory, compliance and planning services.
4 For all other products and services provided by APUC's external auditor.

8.3 Corporate Governance, Risk, and Human Resources and Compensation Committees

The Board has established a Corporate Governance Committee, currently comprised of four directors of APUC: Mr. Steeves (Chair), Mr. Moore, Ms. Saidi, and Mr. Jarratt.

The Board has established a Risk Committee to assist the Board in the oversight of the Corporation's enterprise risk management approach. The committee is currently comprised of four directors of APUC: Ms. Saidi (Chair), Ms. Stapleton Barnes, Mr. Jarratt and Mr. Steeves.

The Board has also established a Human Resources and Compensation Committee, currently comprised of four directors of APUC: Ms. Samil (Chair), Mr. Huskilson, Mr. Ball and Mr. Laney.

8.4 Bankruptcies

Mr. Moore was a director of Telephoto Technologies Inc., a private sports and entertainment media company. Telephoto Technologies Inc. was placed into receivership in August 2010 by Venturelink Funds. Mr. Moore resigned from the board of directors of Telephoto Technologies Inc. in April 2010.

8.5 Conflicts of Interest

To the knowledge of the Corporation, there are no existing or potential material conflicts of interest between APUC or a subsidiary and any current director or officer of APUC or a subsidiary of APUC.

9. LEGAL PROCEEDINGS AND REGULATORY ACTIONS

9.1 Legal Proceedings

The Corporation is not, and was not during the financial year ended December 31, 2019, party to any legal proceedings that involve a claim for damages equal to 10% or more of the current consolidated assets of the Corporation, and the Corporation is not aware of any such legal proceedings that are contemplated.

9.2 Regulatory Actions

During the financial year ended December 31, 2019, there were:

a) no penalties or sanctions imposed against APUC by a court relating to securities legislation or by a securities regulatory authority;

b) no other penalties or sanctions imposed by a court or regulatory body against APUC that would likely be considered important to a reasonable investor in making an investment decision; and

c) no settlement agreements that APUC has entered into with a court relating to securities legislation or with a securities regulatory authority.

10. INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

Other than as disclosed elsewhere in this AIF, no director, executive officer or 10% holder of voting securities, or any associate or affiliate of the foregoing has, or has had, any material interest in any transaction within the three most recently completed financial years or during the current financial year that has materially affected or will materially affect APUC or any of its affiliates.

11. TRANSFER AGENTS AND REGISTRARS

The transfer agent and registrar for the Common Shares, the Series A Shares and the Series D Shares listed on the TSX is AST Trust Company (Canada), at its offices in Toronto, Ontario.

The transfer agent and registrar for the Common Shares, 2018 Subordinated Notes and 2019 Subordinated Notes listed on the NYSE is AST American Stock Transfer & Trust Company, LLC, at its office in Brooklyn, New York.

12. MATERIAL CONTRACTS

The Corporation does not have any material contracts that were not entered into in the ordinary course of business of the Corporation.

13. EXPERTS

Ernst & Young LLP is the external auditor of the Corporation and has confirmed that it is independent with respect to the Corporation within the meaning of the relevant rules and related interpretations prescribed by the relevant professional bodies in Canada and any applicable legislation or regulation, and that it is an independent accountant with respect to the Corporation under all relevant U.S. professional and regulatory standards.

14. ADDITIONAL INFORMATION

Additional information relating to APUC may be found on SEDAR at www.sedar.com. Additional information, including directors' and officers' remuneration and indebtedness, principal holders of APUC's securities and securities authorized for issuance under equity compensation plans is contained in APUC's information circular for its most recent annual meeting. Additional financial information is provided in APUC's financial statements and MD&A for the fiscal year ended December 31, 2019, which are available on SEDAR at www.sedar.com and on EDGAR at www.sec.gov/edgar.

SCHEDULE A

ALGONQUIN POWER & UTILITIES CORP.

MANDATE OF THE AUDIT COMMITTEE

By appropriate resolution of the board of directors (the "**Board**") of Algonquin Power & Utilities Corp., the Audit Committee (the "**Committee**") has been established as a standing committee of the Board with the terms of reference set forth below. Unless the context requires otherwise, the term "Corporation" refers to Algonquin Power & Utilities Corp. and its subsidiaries.

1. PURPOSE

1.1 The Committee's purpose is to:

a) assist the Board's oversight of:

(i) the integrity of the Corporation's financial statements, Management's Discussion and Analysis ("**MD&A**") and other financial reporting;

(ii) the Corporation's compliance with legal and regulatory requirements;

(iii) the external auditor's qualifications, independence and performance;

(iv) the performance of the Corporation's internal audit function and internal auditor;

(v) the communication among management of the Corporation and its subsidiary entities and the Corporation's Chief Executive Officer and its Chief Financial Officer (collectively, "**Management**"), the external auditor, the internal auditor and the Board;

(vi) the review and approval of any related party transactions; and

(vii) any other matters as defined by the Board;

b) prepare and/or approve any report that is required by law or regulation to be included in any of the Corporation's public disclosure documents relating to the Committee.

2. COMMITTEE MEMBERSHIP

2.1 Number of Members – The Committee shall consist of not fewer than three members.

2.2 Independence of Members – Each member of the Committee shall:

a) be a director of the Corporation;
b) not be an officer or employee of the Corporation or any of the Corporation's subsidiary entities or affiliates; and
c) satisfy the independence requirements applicable to members of audit committees under each of the rules of National Instrument 52 110 – Audit Committees of the Canadian Securities Administrators ("**NI 52 110**") and other applicable laws and regulations.

2.3 Financial Literacy – Each member of the Committee shall satisfy the financial literacy requirements applicable to members of audit committees under NI 52 110 and other applicable laws and regulations.

2.4 Chair – The Chair of the Committee shall be selected from among the members of the Committee.

2.5 Annual Appointment of Members – The Committee and its Chair shall be appointed annually by the Board and each member of the Committee shall serve at the pleasure of the Board until he or she resigns, is removed or ceases to be a director.

3. COMMITTEE MEETINGS

3.1 Time and Place of Meetings – The time and place of the meetings of the Committee and the calling of meetings and the procedure in all things at such meetings shall be determined by the Committee; provided, however, that the Committee shall meet at least quarterly and meetings of the Committee shall be convened whenever requested by the external auditors or any member of the Committee in accordance with the Canada Business Corporations Act. No business may be transacted by the Committee at a meeting unless a quorum of a majority of the members of the Committee is present. The Committee shall maintain minutes or other records of its meetings and activities.

3.2 In Camera Meetings – As part of each meeting of the Committee at which it approves, or if applicable, recommends that the Board approve, the annual audited financial statements of the Corporation or at which the Committee reviews the interim financial statements of the Corporation, and at such other times as the Committee deems appropriate, the Committee shall hold *in camera* meetings, and shall also meet separately with each of the persons set forth below to discuss and review specific issues as appropriate:

a) representatives of Management;
b) the external auditor; and
c) the internal audit personnel.

3.3 Attendance at Meetings – The external auditors are entitled to receive notice of every Committee meeting and to be heard and attend thereat at the Corporation's expense. In addition, the Committee may invite to a meeting any officers or employees of the Corporation, legal counsel, advisor and other persons whose attendance it considers necessary or desirable in order to carry out its responsibilities.

4. COMMITTEE AUTHORITY AND RESOURCES

4.1 Direct Channels of Communication – The Committee shall have direct channels of communication with the Corporation's internal and external auditors to discuss and review specific issues as appropriate.

4.2 Retaining and Compensating Advisors – The Committee, or any member of the Committee with the approval of the Committee, may retain at the expense of the Corporation such outside legal, accounting (other than the external auditor) or other advisors on such terms as the Committee may consider appropriate and shall not be required to obtain any other approval in order to retain or compensate any such advisors.

4.3 Funding – The Corporation shall provide for appropriate funding, as determined by the Committee, for payment of compensation of the external auditor and any advisor retained by the Committee under Section 4.2 of this mandate.

4.4 Investigations – The Committee shall have unrestricted access to the personnel and documents of the Corporation and the Corporation's subsidiary entities and shall be provided with the resources necessary to carry out its responsibilities.

5. REMUNERATION OF COMMITTEE MEMBERS

5.1 Director Fees Only – No member of the Committee may accept, directly or indirectly, fees from the Corporation or any of its subsidiary entities other than remuneration for acting as a director or member of the Committee or any other committee of the Board.

5.2 Other Payments – For greater certainty, no member of the Committee shall accept any consulting, advisory or other compensatory fee from the Corporation. For purposes of Section 5.1, the indirect acceptance by a member of the Committee of any fee includes acceptance of a fee by an immediate family member or a partner, member or executive officer of, or a person who occupies a similar position with, an entity that provides accounting, consulting, legal, investment banking or financial advisory services to the Corporation or any of its subsidiaries, other than limited partners, non-managing members and those occupying similar positions who, in each case, have no active role in providing services to the entity.

6. DUTIES AND RESPONSIBILITIES OF THE COMMITTEE

6.1 Overview – The Committee's principal responsibility is one of oversight. Management is responsible for preparing the Corporation's financial statements and the external auditor is responsible for auditing those financial statements.

6.2 The Committee's specific duties and responsibilities are as follows:

a) Financial and Related Information

(i) Annual Financial Statements – The Committee shall review and discuss with Management and the external auditor the Corporation's annual financial statements and related MD&A and if applicable, report thereon to the Board as a whole before they approve such statements and MD&A.

(ii) Interim Financial Statements – The Committee shall review and discuss with Management and the external auditor the Corporation's interim financial statements and related MD&A and if applicable, report thereon to the Board as a whole before they approve such statements and MD&A.

(iii) Prospectuses and Other Documents – The Committee shall review and discuss with Management and the external auditor the financial information, financial statements and related MD&A appearing in any prospectus, annual report, annual information form, management information circular or any other public disclosure document prior to its public release or filing and if applicable, report thereon to the Board as a whole.

(iv) Accounting Treatment – Prior to the completion of the annual external audit, and at any other time deemed advisable by the Committee, the Committee shall review and discuss with Management and the external auditor (and shall arrange for the documentation of such discussions in a manner it deems appropriate) the quality and not just the acceptability of the Corporation's accounting principles and financial statement presentation, including, without limitation, the following:

A) all critical accounting policies and practices to be used, including, without limitation, the reasons why certain estimates or policies are or are not considered critical and how current and anticipated future events impact those determinations and an assessment of Management's disclosures along with any significant proposed modifications by the auditors that were not included;

B) all alternative treatments within generally accepted accounting principles for policies and practices related to material items that have been discussed with Management, including, without limitation, ramification of the use of such alternative disclosure and treatments, and the treatment preferred by the external auditor, which discussion should address recognition, measurement and disclosure consideration related to the accounting for specific transactions as well as general accounting policies. Communications regarding specific transactions should identify the underlying facts, financial statement accounts impacted and applicability of existing corporate accounting policies to the transaction. Communications regarding general accounting policies should focus on the initial selection of, and changes in, significant accounting policies, the impact of the Management's judgments and accounting estimates and the external auditor's judgments about the quality of the Corporation's accounting principles. Communications regarding specific transactions and general accounting policies should include the range of alternatives available under generally accepted accounting principles discussed by Management and the auditors and the reasons for selecting the chosen treatment or policy. If the external auditor's preferred accounting treatment or accounting policy is not selected, the reasons therefore should also be reported to the Committee;

C) other material written communications between the external auditor and Management, such as any management letter, schedule of unadjusted differences, listing of adjustments and reclassifications not recorded, management representation letter, report on observations and recommendations on internal controls, engagement letter and independence letter;

D) major issues regarding financial statement presentations;

E) any significant changes in the Corporation's selection or application of accounting principles;

F) the effect of regulatory and accounting initiatives, as well as off balance sheet structures, on the financial statements of the Corporation; and

G) the adequacy of the Corporation's internal controls and any special audit steps adopted in light of control deficiencies.

(v) Disclosure of Other Financial Information – The Committee shall:

A) review earnings releases, and review and discuss generally with Management, the type and presentation of information to be included in, all public disclosure by the Corporation containing audited, unaudited or forward-looking financial information in advance of its public release by the Corporation, including, without limitation, earnings guidance and financial information based on unreleased financial statements;

B) discuss generally with Management the type and presentation of information to be included in earnings and any other financial information given to analysts and rating agencies, if any; and

C) satisfy itself that adequate procedures are in place for the review of the Corporation's disclosure of financial information extracted or derived from the Corporation's financial statements, other than the Corporation's financial statements, MD&A and earnings press releases, and shall periodically assess the adequacy of those procedures.

b) External Auditor

(i) Authority with Respect to External Auditor – As a representative of the Corporation's shareholders and as a committee of the Board, the Committee shall be directly responsible for the appointment, compensation, retention, termination and oversight of the work of the external auditor (including, without limitation, resolution of disagreements between Management and the auditor regarding financial reporting) for the purpose of preparing or issuing an audit report or performing other audit, review or attest services for the Corporation. In this capacity, the Committee shall have sole authority for recommending the person to be proposed to the Corporation's shareholders for appointment as external auditor, for determining whether at any time the incumbent external auditor should be removed from office, and for determining the compensation of the external auditor. The Committee shall require the external auditor to confirm in an engagement letter to the Committee each year that the external auditor is accountable to the Board and the Committee as representatives of shareholders and that it will report directly to the Committee.

(ii) Approval of Audit Plan – The Committee shall approve, prior to the external auditor's audit, the external auditor's audit plan (including, without limitation, staffing), the scope of the external auditor's review and all related fees.

(iii) Independence – The Committee shall satisfy itself as to the independence of the external auditor. As part of this process:

A) The Committee shall require the external auditor to submit on a periodic basis to the Committee a formal written statement confirming its independence under applicable laws and regulations and delineating all relationships between the auditor and the Corporation and the Committee shall actively engage in a dialogue with the external auditor with respect to any disclosed relationships or services that may impact the objectivity and independence of the external auditor and take, or, if applicable, recommend that the Board take, any action the Committee considers appropriate in response to such report to satisfy itself of the external auditor's independence.

B) In accordance with applicable laws and regulations, the Committee shall pre-approve any non-audit services (including, without limitation, fees therefor) provided to the Corporation or its subsidiaries by the external auditor or any auditor of any such subsidiary and shall consider whether these services are compatible with the external auditor's independence, including, without limitation, the nature and scope of the specific non-audit services to be performed and whether the audit process would require the external auditor to review any advice rendered by the external auditor in connection with the provision of non-audit services. The Committee may delegate to one or more designated members of the Committee, such designated members not being members of management, the authority to approve additional non-audit services that arise between Committee meetings, provided that such designated members report any such approvals to the Committee at the next scheduled meeting.

C) The Committee shall establish a policy setting out the restrictions on the Corporation's subsidiary entities hiring partners, employees, former partners and former employees of the Corporation's external auditor or former external auditor.

(iv) Rotating of Auditor Partner – The Committee shall evaluate the performance of the external auditor and whether it is appropriate to adopt a policy of rotating lead or responsible partners of the external auditors.

(v) Review of Audit Problems and Internal Audit – The Committee shall review with the external auditor:

A) any problems or difficulties the external auditor may have encountered, including, without limitation, any restrictions on the scope of activities or access to required information, and any disagreements with Management and any management letter provided by the auditor and the Corporation's response to that letter;

B) any changes required in the planned scope of the internal audit; and

C) the internal audit department's responsibilities, budget and staffing.

(vi) Review of Proposed Audit and Accounting Changes – The Committee shall review major changes to the Corporation's auditing and accounting principles and practices suggested by the external auditor.

(vii) Regulatory Matters – The Committee shall discuss with the external auditor the matters required to be discussed by Section 5741 of the CICA Handbook – Assurance relating to the conduct of the audit.

c) Internal Audit Function – Controls

(i) Regular Reporting – Internal audit personnel shall report regularly to the Committee.

(ii) Oversight of Internal Controls – The Committee shall oversee Management's design and implementation of and reporting on the Corporation's internal controls and review the adequacy and effectiveness of Management's financial information systems and internal controls. The Committee shall periodically review and approve the mandate, plan, budget and staffing of internal audit personnel. The Committee shall direct Management to make any changes it deems advisable in respect of the internal audit function.

(iii) Review of Audit Problems – The Committee shall review with the internal audit personnel: any problem or difficulties the internal audit personnel may have encountered, including, without limitation, any restrictions on the scope of activities or access to required information, and any significant reports to Management prepared by the internal audit personnel and Management's responses thereto.

(iv) Review of Internal Audit Personnel – The Committee shall review the appointment, performance and replacement of the senior internal auditing personnel and the activities, organization structure and qualifications of the persons responsible for the internal audit function.

d) Risk Assessment and Risk Management

(i) Risk Exposure – The Committee shall discuss with the external auditor, internal audit personnel and Management periodically the Corporation's major financial risk exposures and the steps Management has taken to monitor and control such exposures.

(ii) Investment Practices – The Committee shall review Management's plans and strategies around investment practices, banking performance and treasury risk management.

(iii) Compliance with Covenants – The Committee shall review Management's procedures to assess compliance by the Corporation with its loan covenants and restrictions, if any.

e) Legal Compliance

(i) On at least a quarterly basis, the Committee shall review with the Corporation's legal counsel, external auditor and Management any legal matters (including, without limitation, litigation, regulatory investigations and inquiries, changes to applicable laws and regulations, complaints or published reports) that could have a significant impact on the Corporation's financial position, operating results or financial statements and the Corporation's compliance with applicable laws and regulations.

(ii) The Committee shall review and, if applicable, advise the Board with respect to the Corporation's policies and procedures regarding compliance with applicable laws and regulations and shall notify Management and, if applicable, the Board, promptly after becoming aware of any material non-compliance by the Corporation with applicable laws and regulations.

f) Whistle Blowing – The Committee shall establish procedures for:

(i) the receipt, retention and treatment of complaints received by the Corporation regarding accounting, internal accounting controls or auditing matters; and

(ii) the confidential, anonymous submission by employees of the Corporation's subsidiary entities of concerns regarding questionable accounting or auditing matters.

g) Review of the Management's Certifications and Reports – The Committee shall review and discuss with Management all certifications of financial information, management reports on internal controls and all other management certifications and reports relating to the Corporation's financial position or operations required to be filed or released under applicable laws and regulations prior to the filing or release of such certifications or reports.

h) Liaison – The Committee shall assess whether appropriate liaison and co–operation exist between the external auditor and internal audit personnel and provide a direct channel of communication between external and internal auditors and the Committee.

i) Public Reports – The Committee shall prepare and/or approve any report that is required by law or regulation to be included in any of the Corporation's public disclosure documents relating to the Committee.

j) Other Matters – The Committee may, in addition to the foregoing, perform such other functions as may be necessary or appropriate for the performance of its oversight function.

7. REPORTING TO THE BOARD

7.1 Regular Reporting – If applicable, the Committee shall report to the Board following each meeting of the Committee and at such other times as the Committee may determine to be appropriate.

8. EVALUATION OF COMMITTEE PERFORMANCE

8.1 Performance Review – The Committee shall periodically assess its performance.

8.2 Amendments to Mandate

a) Review by Committee – The Committee shall periodically review and discuss the adequacy of this mandate and if applicable, recommend any proposed changes to the Board.

b) Review by Board – The Board will review and reassess the adequacy of the mandate periodically, as it considers appropriate.

9. LEGISLATIVE AND REGULATORY CHANGES

9.1 Compliance – It is the Board's intention that this mandate shall reflect at all times all legislative and regulatory requirements applicable to the Committee. Accordingly, this mandate shall be deemed to have been updated to reflect any amendments to such legislative and regulatory requirements and shall be formally amended at least every fourteen months to reflect such amendments.

10. CURRENCY OF MANDATE

10.1 Currency of Mandate – This mandate was approved by the Board of Directors of Algonquin Power & Utilities Corp. effective March 31, 2010. Last updated on March 1, 2018.

SCHEDULE B

GLOSSARY OF TERMS

In this AIF, the following terms have the meanings set forth below, unless otherwise indicated:

"**2018 Notes Interest Reset Date**" has the meaning ascribed thereto under "Description of Capital Structure – Subordinated Notes".

"**2018 Subordinated Notes**" has the meaning ascribed thereto under "General Development of the Business – Three Year History and Significant Acquisitions – Fiscal 2018 – Corporate".

"**2019 Notes Interest Reset Date**" has the meaning ascribed thereto under "Description of Capital Structure – Subordinated Notes".

"**2019 Novel Coronavirus**" has the meaning given to it in Caution Concerning Forward-looking Statements and Forward-looking Information.

"**2019 Subordinated Notes**" has the meaning ascribed thereto under "General Development of the Business – Three Year History and Significant Acquisitions – Fiscal 2019 – Corporate".

"**AAGES**" means Abengoa-Algonquin Global Energy Solutions, a joint venture with Abengoa.

"**AAGES Secured Credit Facility**" has the meaning ascribed thereto under "General Development of the Business – Three Year History and Significant Acquisitions – Fiscal 2018 – Corporate".

"**Abengoa**" means Abengoa S.A.

"**Additional Atlantica Investment**" has the meaning ascribed thereto under "General Development of the Business – Three Year History and Significant Acquisitions – Fiscal 2018 – Corporate".

"**AIF**" means this annual information form.

"**Amended and Restated Rights Plan**" has the meaning ascribed thereto under *"*Description of Capital Structure – Shareholders' Rights Plan*".*

"**American Water**" has the meaning ascribed thereto under "General Development of the Business – Three Year History and Significant Acquisitions – Fiscal 2019 – Regulated Services Group".

"**Amherst Island Wind Facility**" has the meaning ascribed thereto under "Description of the Business – Renewable Energy Group – Wind Power Generating Facilities – Selected Facilities".

"**APCI**" means Algonquin Power Corporation Inc.

"**APCo**" has the meaning ascribed thereto under "Corporate Structure – Name, Address and Incorporation".

"**APSC**" means Arkansas Public Services Commission.

"**APUC**" has the meaning ascribed thereto under "Corporate Structure – Name, Address and Incorporation".

"**Ascendant**" has the meaning ascribed thereto under "General Development of the Business – Three Year History and Significant Acquisitions – Fiscal 2019 – Corporate".

"**Atlantica**" has the meaning ascribed thereto under "General Development of the Business – Renewable Energy Group".

"**AY Holdings**" has the meaning ascribed thereto under "Corporate Structure – Intercorporate Relationships".

"**Bakersfield I Solar Facility**" means the 20 MW Bakersfield solar generating facility in California.

"**BELCO**" has the meaning ascribed thereto under "General Development of the Business – Three Year History and Significant Acquisitions – Fiscal 2019 – Corporate".

"**Board**" means the Algonquin Power & Utilities Corp. board of directors.

"**BRRBA**" means base revenue requirement balancing account.

"**CalPeco Electric System**" means an electricity distribution utility in the Lake Tahoe basin and surrounding areas.

"**CC&N**" has the meaning ascribed thereto under "Corporate Development Activities – Development of Regulated Services Assets – Mid-West Wind Development Project".

"**Collateral Reset Level**" has the meaning ascribed thereto under "Enterprise Risk Factors - Risk Factors Relating to Strategic Planning and Execution".

"**Common Shares**" means the common shares of Algonquin Power & Utilities Corp.

"**Corporation**" has the meaning ascribed thereto under "Corporate Structure – Name, Address and Incorporation".

"**Corporation Credit Facility**" has the meaning ascribed thereto under "General Development of the Business – Three Year History and Significant Acquisitions – Fiscal 2018 – Corporate".

"**CPUC**" means California Public Utilities Commission.

"**DBRS**" means the credit rating agency Dominion Bond Rating Service Limited.

"**Deerfield Wind Facility**" means the Deerfield wind energy facility in Michigan.

"**EDG**" has the meaning ascribed thereto under "Corporate Structure – Intercorporate Relationships".

"**EGNB**" has the meaning ascribed thereto under "General Development of the Business – Three Year History and Significant Acquisitions – Fiscal 2018 – Regulated Services Group".

"**EGNB Acquisition**" has the meaning ascribed thereto under "General Development of the Business – Three Year History and Significant Acquisitions – Fiscal 2018 – Regulated Services Group".

"**Empire**" has the meaning ascribed thereto under "Corporate Structure – Intercorporate Relationships".

"**Empire District Electric System**" means an electricity distribution utility in Missouri, Kansas, Oklahoma and Arkansas.

"**Energy Service**" has the meaning ascribed thereto under "Description of the Business – Regulated Services Group – Electric Distribution Systems – Selected Facilities".

"**EnergyNorth Gas System**" means a natural gas distribution utility in New Hampshire.

"**EPC**" means engineering, procurement and construction.

"**ERCOT**" means Electric Reliability Council of Texas.

"**ERM**" means enterprise risk management.

"**FERC**" means the Federal Energy Regulatory Commission.

"**FIT**" means feed-in tariff.

"**Fitch**" means Fitch Ratings, Inc.

"**GAAP**" means Generally Accepted Accounting Principles.

"**GAF**" has the meaning ascribed thereto under "Description of the Business – Regulated Services Group – Description of Operations – Natural Gas Distribution Systems – Selected Facilities".

"**Granite State Electric System**" means an electricity distribution utility in New Hampshire.

"**Great Bay Solar Facility**" means the 75 MW Great Bay solar facility in Somerset County, Maryland.

"**Greening the Fleet**" has the meaning ascribed thereto under "Corporate Development Activities – Development of Regulated Services Assets".

"**GW**" means gigawatt.

"**IESO**" means Independent Electricity System Operator for Ontario.

"**Initial Atlantica Investment**" has the meaning ascribed thereto under "General Development of the Business – Three Year History and Significant Acquisitions – Fiscal 2017 – Corporate".

"**ISO**" means independent system operator.

"**ISO-NE**" means Independent System Operator New England.

“**JPMVEC**” has the meaning ascribed thereto under “Description of the Business – Renewable Energy Group – Description of Operations – Wind Power Generating Facilities – Selected Facilities”.

“**KCC**” means State Corporation Commission of the State of Kansas.

“**kV**” means kilovolt.

“**Liberty Park Water**” has the meaning ascribed thereto under “Description of the Business Regulated Services Group – Description of Operations – Water Distribution and Wastewater Collection Systems”.

"Liberty Park Water System” has the meaning ascribed thereto under “Description of the Business Regulated Services Group – Description of Operations – Water Distribution and Wastewater Collection Systems”.

“**Liberty Power Bilateral Facility**” has the meaning ascribed thereto under “General Development of the Business – Three Year History and Significant Acquisitions – Fiscal 2017 – Renewable Energy Group”.

“**Liberty Utilities Canada**” has the meaning ascribed thereto under “Corporate Structure – Intercorporate Relationships”.

“**LIBOR**” has the meaning ascribed thereto in the first supplemental indenture dated as of October 17, 2018 between APUC, American Stock Transfer & Trust Company, LLC and AST Trust Company (Canada) providing for the issue of the 2018 Subordinated Notes and in the second supplemental indenture dated as of May 23, 2019 between APUC, American Stock Transfer & Trust Company, LLC and AST Trust Company (Canada) providing for the issue of the 2019 Subordinated Notes.

“**LPSCo System**” means the Litchfield Park water and wastewater system in Arizona.

“**Luning Solar Facility**” has the meaning ascribed thereto under “General Development of the Business – Three Year History and Significant Acquisitions – Fiscal 2017 – Regulated Services Group”.

“**Manitoba Hydro**” means the Manitoba Hydro-Electric Board.

“**MD&A**” has the meaning ascribed thereto under “Non-GAAP Financial Measures”.

“**MDPU**” means The Massachusetts Department of Public Utilities.

“**Midstates Gas Systems**” means natural gas distribution utility assets in Missouri, Iowa and Illinois.

“**Minonk Wind Facility**” means the Minonk wind energy facility in Illinois.

“**MISO**” means Midcontinent Independent System Operator, Inc.

“**Moody’s**” means Moody’s Investors Services, Inc.

“**MPSC**” means Missouri Public Services Commission.

“**MW**” means megawatt.

“**NB Energy Board**” means the New Brunswick Energy and Utilities Board.

“**New Brunswick Gas System**” means the natural gas distribution utility assets in New Brunswick.

“**NERC**” means the North American Electric Reliability Corporation.

“**Net Energy Sales**” has the meaning ascribed thereto under “Non-GAAP Financial Measures”.

“**Net Utility Sales**” has the meaning ascribed thereto under “Non-GAAP Financial Measures”.

“**New England Gas System**” means natural gas distribution utility assets in Massachusetts.

“**New York American Water**” has the meaning ascribed thereto under “General Development of the Business – Three Year History and Significant Acquisitions – Fiscal 2019 – Regulated Services Group”.

“**NHPUC**” means the New Hampshire Public Utilities Commission.

“**NV Energy**” means NV Energy, Inc.

“**NYSE**” means New York Stock Exchange.

“**OATT**” means open access transmission tariff.

“**OCC**” means Corporation Commission of Oklahoma.

“**Odell Wind Facility**” means the 200 MW Odell wind facility in Cottonwood, Jackson, Martina and Watonwan counties in Minnesota.

“**OPEB**” has the meaning ascribed thereto under “Enterprise Risk Factors – Risk Factors Relating to Financing and Financial Reporting”.

“**Peach State Gas System**” means natural gas distribution utility assets in Georgia.

“**PGA**” means purchased gas adjustment.

“**PJM**” means PJM Interconnection.

“**PPA**” means power purchase agreement.

“**Primary Energy Production Hedge**” has the meaning ascribed thereto under “Description of the Business – Renewable Energy Group – Description of Operations – Wind Power Generating Facilities – Selected Facilities”.

“**PTC**” means production tax credit.

“**Reinvestment Plan**” has the meaning ascribed thereto under “Dividends – Dividend Reinvestment Plan”.

“**RPS**” means renewable portfolio standards.

“**S&P**” means Standard & Poor’s Financial Services LLC.

“**Sandy Ridge Wind Facility**” means the Sandy Ridge wind energy facility in Texas.

“**SEC**” means U.S. Securities and Exchange Commission

“**Senate Wind Facility**” means the Senate wind energy facility in Texas.

“**Series A Shares**” has the meaning ascribed thereto under “Dividends – Preferred Shares”.

“**Series A Shares Redemption Right**” has the meaning ascribed thereto under “Description of Capital Structure – Preferred Shares”.

“**Series B Shares**” has the meaning ascribed thereto under “Description of Capital Structure – Preferred Shares”.

“**Series C Shares**” has the meaning ascribed thereto under “Dividends – Preferred Shares”.

“**Series D Shares**” has the meaning ascribed thereto under “Dividends – Preferred Shares”.

“**Series D Shares Redemption Right**” has the meaning ascribed thereto under “Description of Capital Structure – Preferred Shares”.

“**Series E Shares**” has the meaning ascribed thereto under “Description of Capital Structure – Preferred Shares”.

“**Series F Shares**” has the meaning ascribed thereto under “General Development of the Business – Three Year History and Significant Acquisitions – Fiscal 2018 – Corporate”.

“**Series G Shares**” has the meaning ascribed thereto under “General Development of the Business – Three Year History and Significant Acquisitions – Fiscal 2019 – Corporate”.

“**Shady Oaks Wind Facility**” means the Shady Oaks wind energy facility in Illinois.

“**SLG**” has the meaning ascribed thereto under “General Development of the Business – Three Year History and Significant Acquisitions – Fiscal 2017 – Regulated Services Group”.

“**SPP**” means Southwest Power Pool.

“**St. Lawrence Gas System**” means natural gas distribution utility assets in northern New York State.

“**St. Leon LP**” has the meaning ascribed thereto under “Corporate Structure – Intercorporate Relationships”.

“**St. Leon Wind Facility**” means the 104 MW wind facility located at St. Leon, Manitoba.

“**Tinker Hydro Facility**” means the electric generating facility and transmission assets in New Brunswick.

“**Turquoise Solar Facility**” means the 10 MW solar generating facility located in Washoe County, Nevada.

“**TSX**” means the Toronto Stock Exchange.

"**U.S. Exchange Act**" has the meaning ascribed thereto under "Enterprise Risk Factors – Risk Factors Relating to Financing and Financial Reporting".

"**Wataynikaneyap Power Transmission Project**" has the meaning ascribed thereto under "Corporate Development Activities – Development of Regulated Services Assets – Wataynikaneyap Power Transmission Project".

"**Windsor Locks Thermal Facility**" has the meaning ascribed thereto under the heading "Description of the Business – Renewable Energy Group – Description of Operations – Thermal (Cogeneration) Electric Generating Facilities – Selected Facilities".

Consolidated Financial Statements of

Algonquin Power & Utilities Corp.

For the years ended December 31, 2019 and 2018

MANAGEMENT'S REPORT

Financial Reporting

The preparation and presentation of the accompanying consolidated financial statements, MD&A and all financial information in the consolidated financial statements are the responsibility of management and have been approved by the Board of Directors. The consolidated financial statements have been prepared in accordance with U.S. generally accepted accounting principles. Financial statements by nature include amounts based upon estimates and judgments. When alternative accounting methods exist, management has chosen those it deems most appropriate in the circumstances. Management has prepared the financial information presented elsewhere in this document and has ensured that it is consistent with that in the consolidated financial statements.

The Board of Directors and its committees are responsible for all aspects related to governance of the Company. The Audit Committee of the Board of Directors, composed of directors who are unrelated and independent, has a specific responsibility to oversee management's efforts to fulfill its responsibilities for financial reporting and internal controls related thereto. The Committee meets with management and independent auditors to review the consolidated financial statements and the internal controls as they relate to financial reporting. The Audit Committee reports its findings to the Board of Directors for its consideration in approving the consolidated financial statements for issuance to the shareholders.

Internal Control over Financial Reporting

Management is also responsible for establishing and maintaining adequate internal control over financial reporting. The Company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of consolidated financial statements for external purposes in accordance with generally accepted accounting principles.

During the year ended December 31, 2019, the Company acquired Enbridge Gas New Brunswick Limited Partnership ("New Brunswick Gas") and St. Lawrence Gas Company, Inc. ("St. Lawrence Gas"). Management is in the process of evaluating the existing controls and procedures of New Brunswick Gas and St. Lawrence Gas and integrating financial reporting and controls for New Brunswick Gas and St. Lawrence gas into the Company's internal control over financial reporting. The financial information for these acquisitions is included in this MD&A and in note 3 to the consolidated financial statements. As permitted by National Instrument 52-109 and the U.S. Securities and Exchange Commission, due to the complexity associated with assessing internal controls during integration efforts, the Company excluded these acquisitions from its evaluation of the effectiveness of the Company's internal controls over financial reporting as of December 31, 2019 (representing approximately 4% of its total assets as of December 31, 2019 and approximately 2% of its revenues for the year ended December 31, 2019).

Management assessed the effectiveness of the Company's internal control over financial reporting as of December 31, 2019, based on the framework established in *Internal Control – Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on this assessment, management concluded that the Company maintained effective internal control over financial reporting as of December 31, 2019.

February 27, 2020

/s/ Ian Robertson
Chief Executive Officer

/s/ David Bronicheski
Chief Financial Officer

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Shareholders and Directors of Algonquin Power & Utilities Corp.

Opinion on the Consolidated Financial Statements

We have audited the accompanying consolidated balance sheets of Algonquin Power & Utilities Corp. (the "Company"), as of December 31, 2019 and 2018, the related consolidated statements of operations, comprehensive income, equity and cash flows for the years then ended, and the related notes (collectively referred to as the "consolidated financial statements"). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2019 and 2018, and the results of its operations and its cash flows for the years then ended in conformity with U.S. generally accepted accounting principles.

Report on Internal Control over Financial Reporting

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) ("PCAOB"), the Company's internal control over financial reporting as of December 31, 2019, based on the criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework), and our report dated February 27, 2020 expressed an unqualified opinion thereon.

Basis for Opinion

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

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures include examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. We believe that our audits provide a reasonable basis for our opinion.

Critical Audit Matter

The critical audit matter communicated below is a matter arising from the current period audit of the consolidated financial statements that was communicated or required to be communicated to the audit committee and that: (1) relates to accounts or disclosures that are material to the consolidated financial statements and (2) involved our especially challenging, subjective or complex judgments. The communication of the critical audit matter does not alter in any way our opinion on the consolidated financial statements, taken as a whole, and we are not, by communicating the critical audit matter below, providing a separate opinion on the critical audit matter or on the accounts or disclosures to which it relates.

Accounting for Long-term Investments and Related Financing Arrangements

Description of the Matter

As more fully described in Notes 8 and 17 to the consolidated financial statements, the Company has various long-term investments and related financing arrangements with Atlantica Yield PLC, Abengoa-Algonquin Global Energy Solutions B.V. and other entities. In the current year, the Company also entered into various new long-term investments including Atlantica Yield Energy Solutions Canada Inc., a subsidiary of Atlantica Yield PLC, and AAGES Sugar Creek, amongst others.

The accounting for these investments involves the application of the variable interest model, which includes evaluating whether various entities within these investment structures are variable interest entities ("VIE") and whether the Company is the primary beneficiary of the VIE. If the Company is the primary beneficiary of the VIE, then the VIE is consolidated. These assessments are complex and required significant judgment. Such judgments include a consideration of the adequacy of equity at risk within the entities, consideration of whether other parties to the arrangements are agents or defacto agents and determining the party that has the power to direct the activities of the entities that most significantly affect their economic performance and evaluating the debt and equity characteristics of certain financing instruments. In addition, certain financing arrangements entered into as part of the funding of these investment structures required consideration of whether the financing arrangements are debt or non-controlling interests.

The Company also monitors for reconsideration events relating to these investment structures, which necessitates on-going critical judgments over whether any such events have arisen that require a re-evaluation of prior accounting judgments.

How We Addressed the Matter in Our Audit

We obtained an understanding, evaluated the design and tested the operating effectiveness of controls over the Company's application of the variable interest model, including the process of evaluating whether an entity is a VIE, whether the Company is the primary beneficiary of the VIE, the classification of related financing instruments and the assessment of reconsideration events.

To evaluate the Company's conclusions about the determination of variable interest entities and consolidation, our audit procedures included, amongst others, obtaining and reviewing all agreements associated with the set-up or acquisition of the respective investments, investee financial information and other legal documents. We reviewed management's analysis of the significant activities and evaluated which party has the power to direct such activities, considering the purpose and design of the entity, composition of the board of directors and other legal rights of the parties, including whether there were indicators that other parties to the arrangement were acting in the role of agents or defacto agents. We also compared the rights of each party to underlying legal documents, articles of incorporation and board of directors' minutes. In addition, we performed an evaluation of the various entities' equity and whether such equity at risk was sufficient to conduct its related activities. We analyzed the at-risk equity holder's obligation to absorb the investments' expected losses and right to receive expected residual returns.

We further evaluated the accounting and presentation of related financing instruments by reviewing the agreements and terms related to such instruments and assessing their equity and debt characteristics.

Finally, we inspected new financing arrangements and any changes to related agreements within the respective structures to determine if a reconsideration event arose that necessitated a re-evaluation of previous accounting judgments.

/s/ Ernst & Young LLP

Chartered Professional Accountants

Licensed Public Accountants

We have served as the Company's auditor since 2013.

Toronto, Canada

February 27, 2020

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Shareholders and Directors of Algonquin Power & Utilities Corp.

Opinion on Internal Control over Financial Reporting

We have audited Algonquin Power & Utilities Corp.'s internal control over financial reporting as of December 31, 2019, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) (the "COSO criteria"). In our opinion, Algonquin Power & Utilities Corp. (the "Company") maintained, in all material respects, effective internal control over financial reporting as of December 31, 2019, based on the COSO criteria.

As indicated in the accompanying Internal Controls over Financial Reporting section in Management's Report, management's assessment of and conclusion on the effectiveness of internal control over financial reporting did not include the internal controls of Enbridge Gas New Brunswick Limited Partnership ("New Brunswick Gas") and St. Lawrence Gas Company, Inc. ("St. Lawrence Gas"), which are included in the 2019 consolidated financial statements of the Company and constituted 4% of total assets as of December 31, 2019 and 2% of revenues for the year then ended. Our audit of internal control over financial reporting of the Company also did not include an evaluation of the internal control over financial reporting of New Brunswick Gas and St. Lawrence Gas.

We also have audited, in accordance with the standards of the Public Accounting Oversight Board (United States) ("PCAOB"), the consolidated balance sheets as of December 31, 2019 and 2018, and the consolidated statements of operations, comprehensive income, equity and cash flows for the years then ended, and the related notes, and our report dated February 27, 2020 expressed an unqualified opinion thereon.

Basis for Opinion

The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management's Report. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects.

Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

Definition and Limitations of Internal Control Over Financial Reporting

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ Ernst & Young LLP

Chartered Professional Accountants

Licensed Public Accountants

Toronto, Canada

February 27, 2020

Algonquin Power & Utilities Corp.
Consolidated Statements of Operations

(thousands of U.S. dollars, except per share amounts)	Year ended December 31	
	2019	2018
Revenue		
Regulated electricity distribution	**$ 784,396**	$ 831,196
Regulated gas distribution	**439,153**	431,453
Regulated water reclamation and distribution	**130,488**	128,437
Non-regulated energy sales	**246,601**	235,359
Other revenue	**24,283**	22,018
	1,624,921	1,648,463
Expenses		
Operating expenses	**471,989**	472,466
Regulated electricity purchased	**247,417**	265,166
Regulated gas purchased	**170,487**	183,012
Regulated water purchased	**8,142**	8,796
Non-regulated energy purchased	**17,258**	27,164
Administrative expenses	**56,802**	52,710
Depreciation and amortization	**284,304**	260,772
Loss (gain) on foreign exchange	**3,146**	(58)
	1,259,545	1,270,028
Operating income	**365,376**	378,435
Interest expense on long-term debt and others	**(181,488)**	(152,118)
Income (loss) from long-term investments (note 8)	**399,092**	(84,818)
Other net losses (note 19)	**(44,026)**	(8,402)
Gain (loss) on derivative financial instruments (note 24(b)(iv))	**16,113**	(636)
	189,691	(245,974)
Earnings before income taxes	**555,067**	132,461
Income tax expense (note 18)		
Current	**(16,431)**	(11,347)
Deferred	**(53,686)**	(42,025)
	(70,117)	(53,372)
Net earnings	**484,950**	79,089
Net effect of non-controlling interests (note 17)		
Net effect of non-controlling interests	**62,416**	108,521
Net effect of non-controlling interests held by related party	**(16,482)**	(2,622)
	$ 45,934	$ 105,899
Net earnings attributable to shareholders of Algonquin Power & Utilities Corp.	**$ 530,884**	$ 184,988
Series A and D Preferred shares dividend (note 15)	**8,486**	8,027
Net earnings attributable to common shareholders of Algonquin Power & Utilities Corp.	**$ 522,398**	$ 176,961
Basic net earnings per share (note 20)	**$ 1.05**	$ 0.38
Diluted net earnings per share (note 20)	**$ 1.04**	$ 0.38

See accompanying notes to consolidated financial statements

Algonquin Power & Utilities Corp.
Consolidated Statements of Comprehensive Income

(thousands of U.S. dollars)	Year ended December 31	
	2019	**2018**
Net earnings	**$ 484,950**	$ 79,089
Other comprehensive income (loss):		
Foreign currency translation adjustment, net of tax recovery of $289 and $4,532, respectively (notes 1(u), 24(b)(iii) and 24(b)(iv))	**7,795**	(27,969)
Change in fair value of cash flow hedges, net of tax expense and tax recovery of $3,862 and $952, respectively (note 24(b)(ii))	**10,580**	(2,690)
Change in pension and other post-employment benefits, net of tax recovery and tax expense of $2,735 and $696, respectively (note 10)	**(6,509)**	1,960
Other comprehensive income (loss), net of tax	**11,866**	(28,699)
Comprehensive income	**496,816**	50,390
Comprehensive loss attributable to the non-controlling interests	**(43,506)**	(107,380)
Comprehensive income attributable to shareholders of Algonquin Power & Utilities Corp.	**$ 540,322**	$ 157,770

See accompanying notes to consolidated financial statements

Algonquin Power & Utilities Corp.
Consolidated Balance Sheets

(thousands of U.S. dollars)

	December 31, 2019	December 31, 2018
ASSETS		
Current assets:		
Cash and cash equivalents	**$ 62,485**	$ 46,819
Accounts receivable, net (note 4)	**259,144**	245,728
Fuel and natural gas in storage	**30,804**	43,063
Supplies and consumables inventory	**60,295**	52,537
Regulatory assets (note 7)	**50,213**	59,037
Prepaid expenses	**29,003**	27,283
Derivative instruments (note 24)	**13,483**	9,616
Other assets and long-term investments (notes 8 and 11)	**7,764**	7,522
	513,191	491,605
Property, plant and equipment, net (note 5)	**7,231,664**	6,393,558
Intangible assets, net (note 6)	**47,616**	54,994
Goodwill (note 6)	**1,031,696**	954,282
Regulatory assets (note 7)	**509,674**	401,058
Long-term investments (note 8)		
Investments carried at fair value	**1,294,147**	814,530
Other long-term investments	**121,968**	134,371
Derivative instruments (note 24)	**72,221**	53,192
Deferred income taxes (note 18)	**30,585**	72,415
Other assets (note 11)	**58,708**	28,584
	$ 10,911,470	$ 9,398,589

See accompanying notes to consolidated financial statements

Algonquin Power & Utilities Corp.
Consolidated Balance Sheets

(thousands of U.S. dollars)

	December 31, 2019	December 31, 2018
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable	**$ 150,336**	$ 89,740
Accrued liabilities	**307,952**	235,586
Dividends payable (note 15)	**73,945**	62,613
Regulatory liabilities (note 7)	**41,683**	39,005
Long-term debt (note 9)	**225,013**	13,048
Other long-term liabilities (note 12)	**57,939**	42,337
Derivative instruments (note 24)	**5,898**	14,339
Other liabilities	**9,300**	2,313
	872,066	498,981
Long-term debt (note 9)	**3,706,855**	3,323,747
Regulatory liabilities (note 7)	**556,379**	549,208
Deferred income taxes (note 18)	**491,538**	444,145
Derivative instruments (note 24)	**78,766**	88,503
Pension and other post-employment benefits obligation (note 10)	**224,094**	199,829
Other long-term liabilities (note 12)	**243,401**	255,668
	5,301,033	4,861,100
Redeemable non-controlling interests (note 17)		
Redeemable non-controlling interest, held by related party (note 16(b))	**305,863**	307,622
Redeemable non-controlling interests	**25,913**	33,364
Equity:		
Preferred shares (note 13(b))	**184,299**	184,299
Common shares (note 13(a))	**4,017,044**	3,562,418
Additional paid-in capital	**50,579**	45,553
Deficit	**(367,107)**	(595,259)
Accumulated other comprehensive loss (note 14)	**(9,761)**	(19,385)
Total equity attributable to shareholders of Algonquin Power & Utilities Corp.	**3,875,054**	3,177,626
Non-controlling interests (note 17)		
Non-controlling interests	**457,834**	519,896
Non-controlling interest, held by related party (note 16(c))	**73,707**	—
	531,541	519,896
Total equity	**4,406,595**	3,697,522
Commitments and contingencies (note 22)		
Subsequent events (notes 1(u), 8(a), 9(a), 9(d), 13(a)(iii)) and 24(b)(ii))		
	$ 10,911,470	$ 9,398,589

See accompanying notes to consolidated financial statements

Algonquin Power & Utilities Corp.
Consolidated Statement of Equity

(thousands of U.S. dollars)
For the year ended December 31, 2019

	Algonquin Power & Utilities Corp. Shareholders						
	Common shares	Preferred shares	Additional paid-in capital	Accumulated deficit	Accumulated OCI	Non-controlling interests	Total
Balance, December 31, 2018	$ 3,562,418	$ 184,299	$ 45,553	$ (595,259)	$ (19,385)	$ 519,896	$ 3,697,522
Adoption of ASU 2017-12 on hedging (note 2(a))	—	—	—	(186)	186	—	—
Net earnings (loss)	—	—	—	530,884	—	(45,934)	484,950
Redeemable non-controlling interests not included in equity (note 17)	—	—	—	—	—	(7,476)	(7,476)
Other comprehensive income	—	—	—	—	9,438	2,428	11,866
Dividends declared and distributions to non-controlling interests	—	—	—	(217,464)	—	(37,691)	(255,155)
Dividends and issuance of shares under dividend reinvestment plan (note 13(a)(iii))	68,856	—	—	(68,856)	—	—	—
Contributions received from non-controlling interests	—	—	—	—	—	100,318	100,318
Common shares issued upon conversion of convertible debentures	148	—	—	—	—	—	148
Common shares issued upon public offering, net of cost	364,211	—	—	—	—	—	364,211
Issuance of common shares under employee share purchase plan	2,853	—	—	—	—	—	2,853
Share-based compensation	—	—	12,974	—	—	—	12,974
Common shares issued pursuant to share-based awards	18,558	—	(7,948)	(16,226)	—	—	(5,616)
Balance, December 31, 2019	$ 4,017,044	$ 184,299	$ 50,579	$ (367,107)	$ (9,761)	$ 531,541	$ 4,406,595

See accompanying notes to consolidated financial statements

Algonquin Power & Utilities Corp.
Consolidated Statement of Equity

(thousands of U.S. dollars)
For the year ended December 31, 2018

	Algonquin Power & Utilities Corp. Shareholders						
	Common shares	**Preferred shares**	**Additional paid-in capital**	**Accumulated deficit**	**Accumulated OCI**	**Non-controlling interests**	**Total**
Balance, December 31, 2017	$3,021,699	$ 184,299	$ 38,569	$ (524,311)	$ (2,792)	$ 602,636	$3,320,100
Adoption of Topic 606 on revenue (note 1(t))	—	—	—	1,860	—	—	1,860
Adoption of ASU 2018-02 on tax effects in AOCI	—	—	—	(10,625)	10,625	—	—
Net earnings (loss)	—	—	—	184,988	—	(105,899)	79,089
Redeemable non-controlling interests not included in equity (note 17)	—	—	—	—	—	4,923	4,923
Other comprehensive loss	—	—	—	—	(27,218)	(1,481)	(28,699)
Dividends declared and distributions to non-controlling interests	—	—	—	(187,890)	—	(9,393)	(197,283)
Dividends and issuance of shares under dividend reinvestment plan (note 13(a)(iii))	55,442	—	—	(55,442)	—	—	—
Common shares issued pursuant to public offering, net of costs (note 13(a)(i))	472,180	—	—	—	—	—	472,180
Common shares issued upon conversion of convertible debentures (note 12(h))	447	—	—	—	—	—	447
Common shares issued pursuant to share-based awards (note 13(c))	12,650	—	(4,027)	(3,839)	—	—	4,784
Share-based compensation (note 13(c))	—	—	11,011	—	—	—	11,011
Contributions received from non-controlling interests (note 3(g)), net of costs	—	—	—	—	—	29,110	29,110
Balance, December 31, 2018	$3,562,418	$ 184,299	$ 45,553	$ (595,259)	$ (19,385)	$ 519,896	$3,697,522

See accompanying notes to consolidated financial statements

Algonquin Power & Utilities Corp.
Consolidated Statements of Cash Flows

(thousands of U.S. dollars)	Year ended December 31	
	2019	**2018**
Cash provided by (used in):		
Operating Activities		
Net earnings	**$ 484,950**	$ 79,089
Adjustments and items not affecting cash:		
Depreciation and amortization	**284,304**	260,772
Deferred taxes	**53,686**	42,025
Unrealized gain on derivative financial instruments	**(15,237)**	(1,781)
Share-based compensation expense	**11,042**	7,495
Cost of equity funds used for construction purposes	**(4,896)**	(2,728)
Change in value of investments carried at fair value	**(276,458)**	137,957
Pension and post-employment contributions in excess of expense	**(8,952)**	(6,354)
Distributions received from equity investments, net of income	**7,487**	5,698
Others	**15,031**	16,305
Changes in non-cash operating items (note 23)	**60,303**	(8,126)
	611,260	530,352
Financing Activities		
Increase in long-term debt	**3,614,758**	2,015,533
Decrease in long-term debt	**(3,048,008)**	(1,699,592)
Issuance of common shares, net of costs	**362,364**	473,911
Cash dividends on common shares	**(196,391)**	(166,384)
Dividends on preferred shares	**(8,486)**	(8,027)
Contributions from non-controlling interests, related party (note 17)	**96,752**	305,000
Contributions from non-controlling interests and redeemable non-controlling interests (note 17)	**3,403**	15,250
Production-based cash contributions from non-controlling interest	**3,565**	13,860
Distributions to non-controlling interests, related party (note 16(b) and (c))	**(38,718)**	—
Distributions to non-controlling interests	**(12,251)**	(9,289)
Settlement of derivatives	**(8,732)**	—
Proceeds from exercise of share options	**—**	4,504
Shares surrendered to fund withholding taxes on exercised share options	**(5,282)**	(2,088)
Increase in other long-term liabilities	**10,175**	9,403
Decrease in other long-term liabilities	**(39,783)**	(20,144)
	733,366	931,937
Investing Activities		
Additions to property, plant and equipment and intangible assets	**(581,332)**	(466,369)
Increase in long-term investments	**(669,832)**	(1,005,072)
Acquisitions of operating entities	**(308,423)**	—
Increase in other assets	**(16,690)**	(5,912)
Receipt of principal on development loans receivable	**251,118**	17,950
Decrease in long-term investments	**1,000**	1,158
Proceeds from sale of long-lived assets	**—**	2,912
	(1,324,159)	(1,455,333)
Effect of exchange rate differences on cash and restricted cash	**1,032**	(606)
Increase in cash, cash equivalents and restricted cash	**21,499**	6,350
Cash, cash equivalents and restricted cash, beginning of year	**65,773**	59,423
Cash, cash equivalents and restricted cash, end of year	**$ 87,272**	$ 65,773

Supplemental disclosure of cash flow information:	**2019**	**2018**
Cash paid during the year for interest expense	**$ 171,548**	$ 155,309
Cash paid during the year for income taxes	**$ 14,543**	$ 9,652
Non-cash financing and investing activities:		
Property, plant and equipment acquisitions in accruals	**$ 98,231**	$ 45,154
Issuance of common shares under dividend reinvestment plan and share-based compensation plans	**$ 87,414**	$ 65,767
Issuance of common shares upon conversion of convertible debentures	**$ 155**	$ 468
Sale of property, plant and equipment, intangible assets and accrued liabilities in exchange of note receivable	**$ 57,753**	$ 13,092

See accompanying notes to consolidated financial statements

Algonquin Power & Utilities Corp. ("APUC" or the "Company") is an incorporated entity under the *Canada Business Corporations Act*. APUC's operations are organized across two primary business units consisting of the Regulated Services Group and the Renewable Energy Group. The Regulated Services Group owns and operates a portfolio of regulated electric, natural gas, water distribution and wastewater collection utility systems and transmission operations in the United States and Canada; the Renewable Energy Group owns and operates a diversified portfolio of non-regulated renewable and thermal electric generation assets.

1. Significant accounting policies

(a) Basis of preparation

The accompanying consolidated financial statements and notes have been prepared in accordance with generally accepted accounting principles in the United States ("U.S. GAAP") and follow disclosure required under Regulation S-X provided by the U.S. Securities and Exchange Commission.

(b) Basis of consolidation

The accompanying consolidated financial statements of APUC include the accounts of APUC, its wholly owned subsidiaries and variable interest entities ("VIEs") where the Company is the primary beneficiary (note 1(m)). Intercompany transactions and balances have been eliminated. Interests in subsidiaries owned by third parties are included in non-controlling interests (note 1(s)).

(c) Business combinations, intangible assets and goodwill

The Company accounts for acquisitions of entities or assets that meet the definition of a business as business combinations. Business combinations are accounted for using the acquisition method. Assets acquired and liabilities assumed are measured at their fair value at the acquisition date, except for deferred income taxes which are accounted for as described in note 1(v). Acquisition costs are expensed in the period incurred. When the set of activities does not represent a business, the transaction is accounted for as an asset acquisition and includes acquisition costs.

Intangible assets acquired are recognized separately at fair value if they arise from contractual or other legal rights or are separable. Power sales contracts are amortized on a straight-line basis over the remaining term of the contract ranging from 6 to 25 years from the date of acquisition. Interconnection agreements are amortized on a straight-line basis over their estimated life of 40 years. Customer relationships are amortized on a straight-line basis over their estimated life of 40 years.

Goodwill represents the excess of the purchase price of an acquired business over the fair value of the net assets acquired. Goodwill is generally not included in the rate base on which regulated utilities are allowed to earn a return and is not amortized.

As at September 30 of each year, the Company assesses qualitative and quantitative factors to determine whether it is more likely than not that the fair value of a reporting unit to which goodwill is attributed is less than its carrying amount. If it is more likely than not that a reporting unit's fair value is less than its carrying amount or if a quantitative assessment is elected, the Company calculates the fair value of the reporting unit. The carrying amount of the reporting unit's goodwill is considered not recoverable if the carrying amount of the reporting unit as a whole exceeds the reporting unit's fair value. An impairment charge is recorded for any excess of the carrying value of the goodwill over the implied fair value. Goodwill is tested for impairment between annual tests if an event occurs or circumstances change that would more likely than not reduce the fair value of a reporting unit below its carrying amount.

(d) Accounting for rate regulated operations

The operating companies within the Regulated Services Group are subject to rate regulation generally overseen by the public utility commission of the states and provinces in which they operate (the "Regulator"). The Regulator provides the final determination of the rates charged to customers. APUC's regulated operating companies are accounted for under the principles of U.S. Financial Accounting Standards Board ("FASB") ASC Topic 980, *Regulated Operations* ("ASC 980").

1. Significant accounting policies (continued)

(d) Accounting for rate regulated operations (continued)

Under ASC 980, regulatory assets and liabilities are recorded to the extent that they represent probable future revenue or expenses associated with certain charges or credits that will be recovered from or refunded to customers through the rate making process. Included in note 7 "Regulatory matters" are details of regulatory assets and liabilities, and their current regulatory treatment.

In the event the Company determines that its net regulatory assets are not probable of recovery, it would no longer apply the principles of the current accounting guidance for rate regulated enterprises and would be required to record an after-tax, non-cash charge or credit against earnings for any remaining regulatory assets or liabilities. The impact could be material to the Company's reported financial condition and results of operations.

The U.S. electric, gas and water utilities' accounts are maintained in accordance with the Uniform System of Accounts prescribed by the Federal Energy Regulatory Commission ("FERC"), the Regulator and National Association of Regulatory Utility Commissioners in the United States. The New Brunswick Gas accounts are maintained in accordance with the New Brunswick Gas Distribution Act Uniform Accounting Regulation.

(e) Cash and cash equivalents

Cash and cash equivalents include all highly liquid instruments with an original maturity of three months or less.

(f) Restricted cash

Restricted cash represents reserves and amounts set aside pursuant to requirements of various debt agreements, deposits to be returned back to customers, and certain requirements related to generation and transmission operations. Cash reserves segregated from APUC's cash balances are maintained in accounts administered by a separate agent and disclosed separately as restricted cash in these consolidated financial statements. APUC cannot access restricted cash without the prior authorization of parties not related to APUC.

(g) Accounts receivable

Trade accounts receivable are recorded at the invoiced amount and do not bear interest. The Company maintains an allowance for doubtful accounts for estimated losses inherent in its accounts receivable portfolio. In establishing the required allowance, management considers historical losses adjusted to take into account current market conditions and customers' financial condition, the amount of receivables in dispute, and the receivables aging and current payment patterns. Account balances are charged against the allowance after all means of collection have been exhausted and the potential for recovery is considered remote. The Company does not have any off-balance sheet credit exposure related to its customers.

(h) Fuel and natural gas in storage

Fuel and natural gas in storage is reflected at weighted average cost or first-in-first-out as required by regulators and represents fuel, natural gas and liquefied natural gas that will be utilized in the ordinary course of business of the gas utilities and some generating facilities. Existing rate orders (note 7(e)) and other contracts allow the Company to pass through the cost of gas purchased directly to the customers along with any applicable authorized delivery surcharge adjustments. Accordingly, the net realizable value of fuel and gas in storage does not fall below the cost to the Company.

(i) Supplies and consumables inventory

Supplies and consumables inventory (other than capital spares and rotatable spares, which are included in property, plant and equipment) are charged to inventory when purchased and then capitalized to plant or expensed, as appropriate, when installed, used or become obsolete. These items are stated at the lower of cost and net realizable value. Through rate orders and the regulatory environment, capitalized construction jobs are recovered through rate base and repair and maintenance expenses are recovered through a cost of service calculation. Accordingly, the cost usually reflects the net realizable value.

(in thousands of U.S. dollars, except as noted and per share amounts)

1. Significant accounting policies (continued)

(j) Property, plant and equipment

Property, plant and equipment are recorded at cost. Capitalization of development projects begins when management with the relevant authority has authorized and committed to the funding of a project and it is probable that costs will be realized through the use of the asset or ultimate construction and operation of a facility. Project development costs for rate regulated entities, including expenditures for preliminary surveys, plans, investigations, environmental studies, regulatory applications and other costs incurred for the purpose of determining the feasibility of capital expansion projects, are capitalized either as property, plant and equipment or regulatory assets when it is determined that recovery of such costs through regulated revenue of the completed project is probable.

The costs of acquiring or constructing property, plant and equipment include the following: materials, labour, contractor and professional services, construction overhead directly attributable to the capital project (where applicable), interest for non-regulated property and allowance for funds used during construction ("AFUDC") for regulated property. Where possible, individual components are recorded and depreciated separately in the books and records of the Company. Plant and equipment under finance leases are initially recorded at cost determined as the present value of lease payments to be made over the lease term.

AFUDC represents the cost of borrowed funds and a return on other funds. Under ASC 980, an allowance for funds used during construction projects that are included in rate base is capitalized. This allowance is designed to enable a utility to capitalize financing costs during periods of construction of property subject to rate regulation. For operations that do not apply regulatory accounting, interest related only to debt is capitalized as a cost of construction in accordance with ASC 835, *Interest*. The interest capitalized that relates to debt reduces interest expense on the consolidated statements of operations. The AFUDC capitalized that relates to equity funds is recorded as interest and other income under income from long-term investments on the consolidated statements of operations.

Improvements that increase or prolong the service life or capacity of an asset are capitalized. Costs incurred for major expenditures or overhauls that occur at regular intervals over the life of an asset are capitalized and depreciated over the related interval. Maintenance and repair costs are expensed as incurred.

Grants related to capital expenditures are recorded as a reduction to the cost of assets and are amortized at the rate of the related asset as a reduction to depreciation expense. Grants related to operating expenses such as maintenance and repairs costs are recorded as a reduction of the related expense. Contributions in aid of construction represent amounts contributed by customers, governments and developers to assist with the funding of some or all of the cost of utility capital assets. It also includes amounts initially recorded as advances in aid of construction (note 12(a)) but where the advance repayment period has expired. These contributions are recorded as a reduction in the cost of utility assets and are amortized at the rate of the related asset as a reduction to depreciation expense.

The Company's depreciation is based on the estimated useful lives of the depreciable assets in each category and is determined using the straight-line method with the exception of certain wind assets, as described below. The ranges of estimated useful lives and the weighted average useful lives are summarized below:

	Range of useful lives		Weighted average useful lives	
	2019	**2018**	**2019**	**2018**
Generation	**3 - 60**	3 - 60	**33**	33
Distribution	**5 - 100**	5 - 100	**42**	40
Equipment	**5 - 44**	5 - 43	**10**	10

The Company uses the unit-of-production method for certain components of its wind generating facilities where the useful life of the component is directly related to the amount of production. The benefits of components subject to wear and tear from the power generation process are best reflected through the unit-of-production method. The Company generally uses wind studies prepared by third parties to estimate the total expected production of each component.

1. Significant accounting policies (continued)

(j) Property, plant and equipment (continued)

In accordance with regulator-approved accounting policies, when depreciable property, plant and equipment of the Regulated Services Group are replaced or retired, the original cost plus any removal costs incurred (net of salvage) are charged to accumulated depreciation with no gain or loss reflected in results of operations. Gains and losses will be charged to results of operations in the future through adjustments to depreciation expense. In the absence of regulator-approved accounting policies, gains and losses on the disposition of property, plant and equipment are charged to earnings as incurred.

(k) Commonly owned facilities

The Regulated Services Group owns undivided interests in three electric generating facilities with ownership interest ranging from 7.52% to 60% with a corresponding share of capacity and generation from the facility used to serve certain of its utility customers. The Company's investment in the undivided interest is recorded as plant in service and recovered through rate base. The Company's share of operating costs is recognized in operating, maintenance and fuel expenditures excluding depreciation expense.

(l) Impairment of long-lived assets

APUC reviews property, plant and equipment and intangible assets for impairment whenever events or changes in circumstances indicate the carrying amount may not be recoverable.

Recoverability of assets expected to be held and used is measured by comparing the carrying amount of an asset to undiscounted expected future cash flows. If the carrying amount exceeds the recoverable amount, the asset is written down to its fair value.

(m) Variable interest entities

The Company performs analyses to assess whether its operations and investments represent VIEs. To identify potential VIEs, management reviews contracts under leases, long-term purchase power agreements and jointly owned facilities. VIEs for which the Company is deemed the primary beneficiary are consolidated. In circumstances where APUC is not deemed the primary beneficiary, the VIE is not consolidated (note 8).

The Company has equity and notes receivable interests in two power generating facilities. APUC has determined that both entities are considered VIEs mainly based on total equity at risk not being sufficient to permit the legal entity to finance its activities without additional subordinated financial support. The key decisions that affect the generating facilities' economic performance relate to siting, permitting, technology, construction, operations and maintenance and financing. As APUC has both the power to direct the activities of the entities that most significantly impact its economic performance and the right to receive benefits or the obligation to absorb losses of the entities that could potentially be significant to the entity, the Company is considered the primary beneficiary.

Total net book value of generating assets and long-term debt of these facilities amounts to $60,230 (2018 - $59,288) and $21,754 (2018 - $22,263), respectively. The financial performance of these facilities reflected on the consolidated statements of operations includes non-regulated energy sales of $17,108 (2018 - $17,232), operating expenses and amortization of $4,930 (2018 - $4,634) and interest expense of $2,340 (2018 - $2,557).

(n) Long-term investments and notes receivable

Investments in which APUC has significant influence but not control are either accounted for using the equity method or at fair value. Equity-method investments are initially measured at cost including transaction costs and interest when applicable. APUC records its share in the income or loss of its equity-method investees in income from long-term investments in the consolidated statements of operations. APUC records in the consolidated statements of operations the fluctuations in the fair value of its investees held at fair value and dividend income when it is declared by the investee.

1. Significant accounting policies (continued)

(n) Long-term investments and notes receivable (continued)

Notes receivable are financial assets with fixed or determined payments that are not quoted in an active market. Notes receivable are initially recorded at cost, which is generally face value. Subsequent to acquisition, the notes receivable are recorded at amortized cost using the effective interest method. The Company holds these notes receivable as long-term investments and does not intend to sell these instruments prior to maturity. Interest from long-term investments is recorded as earned and when collectability of both the interest and principal are reasonably assured.

If a loss in value of a long-term investment is considered other than temporary, an allowance for impairment on the investment is recorded for the amount of that loss. An allowance for impairment loss on notes receivable is recorded if it is expected that the Company will not collect all principal and interest contractually due. The impairment is measured based on the present value of expected future cash flows discounted at the note's effective interest rate.

(o) Pension and other post-employment plans

The Company has established defined contribution pension plans, defined benefit pension plans, other post-employment benefit ("OPEB") plans, and supplemental retirement program ("SERP") plans for its various employee groups in Canada and the United States. Employer contributions to the defined contribution pension plans are expensed as employees render service. The Company recognizes the funded status of its defined benefit pension plans, OPEB and SERP plans on the consolidated balance sheets. The Company's expense and liabilities are determined by actuarial valuations, using assumptions that are evaluated annually as of December 31, including discount rates, mortality, assumed rates of return, compensation increases, turnover rates and healthcare cost trend rates. The impact of modifications to those assumptions and modifications to prior services are recorded as actuarial gains and losses in accumulated other comprehensive income ("AOCI") and amortized to net periodic cost over future periods using the corridor method. When settlements of the Company's pension plans occur, the Company recognizes associated gains or losses immediately in earnings if the cost of all settlements during the year is greater than the sum of the service cost and interest cost components of the pension plan for the year. The amount recognized is a pro rata portion of the gains and losses in AOCI equal to the percentage reduction in the projected benefit obligation as a result of the settlement.

The costs of the Company's pension for employees are expensed over the periods during which employees render service and the service costs are recognized as part of administrative expenses in the consolidated statements of operations.The components of net periodic benefit cost other than the service cost component are included in other net losses in the consolidated statements of operations.

(p) Asset retirement obligations

The Company recognizes a liability for asset retirement obligations based on the fair value of the liability when incurred, which is generally upon acquisition, during construction or through the normal operation of the asset. Concurrently, the Company also capitalizes an asset retirement cost, equal to the estimated fair value of the asset retirement obligation, by increasing the carrying value of the related long-lived asset. The asset retirement costs are depreciated over the asset's estimated useful life and are included in depreciation and amortization expense on the consolidated statements of operations. Increases in the asset retirement obligation resulting from the passage of time are recorded as accretion of asset retirement obligation in the consolidated statements of operations. Actual expenditures incurred are charged against the obligation.

(q) Leases

The Company adopted ASU 2016-02, *Leases (Topic 842)* ("ASC 842") during 2019 using a modified retrospective approach.

The Company leases buildings, vehicles, rail cars, and office equipment for use in its day-to-day operations. The Company has options to extend the lease term of many of its lease agreements, with renewal periods ranging from one to five years. As at the consolidated balance sheet date, the Company is not reasonably certain that these renewal options will be exercised.

(in thousands of U.S. dollars, except as noted and per share amounts)

1. Significant accounting policies (continued)

(q) Leases (continued)

The Renewable Energy Group enters into land easement agreements for the operation of its generation facilities. In assessing whether these contracts contain leases, the Company considers whether it has exclusive use of the land. In the majority of situations, the landowner or grantor of the easement still has full access to the land and can use the land in any capacity, as long as it does not interfere with the Company's operations. Therefore, these land easement agreements do not contain leases. For land easement agreements that provide exclusive access to and use of the land, these agreements meet the definition of a lease and are within the scope of ASC 842.

The Regulated Services Group enters into easement agreements for the operation of its utilities. For all easements that existed or were expired as of January 1, 2019, the practical expedient was taken to not change the legacy accounting for these easement contracts. For new easement contracts entered into subsequent to January 1, 2019, the Company considers whether they contain a lease.

The implementation of ASC 842 did not have an impact on the Company's existing finance leases. The weighted-average discount rate as of December 31, 2019 for the Company's finance lease assets and liabilities is 6.45% and the weighted-average remaining lease term of the Company's finance leases is 5.55 years.

New right-of-use assets and lease liabilities of $8,295 were recognized for the Company's operating leases as at January 1, 2019. As a result of the acquisition of Enbridge Gas New Brunswick Limited Partnership ("New Brunswick Gas") on October 1, 2019 (note 3(a)), the Company acquired new right-of-use assets and assumed lease liabilities of $1,316. The weighted-average discount rate as of December 31, 2019 for the Company's operating lease assets and liabilities is 3.95% and the weighted-average remaining lease term is 13.49 years.

The right-of-use assets are included in property, plant and equipment while lease liabilities are included in other liabilities on the consolidated balance sheets.

The Company's operating leases payments for the next five years and thereafter are as follows:

Year 1	Year 2	Year 3	Year 4	Year 5	Thereafter	Total
$ 2,115	$ 1,138	$ 688	$ 659	$ 642	$ 5,195	$ 10,437

The lease payments for the Company's finance leases are expected to be approximately $539 annually for the next five years, and $318 thereafter.

(r) Share-based compensation

The Company has several share-based compensation plans: a share option plan; an employee share purchase plan ("ESPP"); a deferred share unit ("DSU") plan; a restricted share unit ("RSU") plan and a performance share unit ("PSU") plan. Equity-classified awards are measured at the grant date fair value of the award. The Company estimates grant date fair value of options using the Black-Scholes option pricing model. The fair value is recognized over the vesting period of the award granted, adjusted for estimated forfeitures. The compensation cost is recorded as administrative expenses in the consolidated statements of operations and additional paid-in capital in equity. Additional paid-in capital is reduced as the awards are exercised, and the amount initially recorded in additional paid-in capital is credited to common shares.

(s) Non-controlling interests

Non-controlling interests represent the portion of equity ownership in subsidiaries that is not attributable to the equity holders of APUC. Non-controlling interests are initially recorded at fair value and subsequently adjusted for the proportionate share of earnings and other comprehensive income ("OCI") attributable to the non-controlling interests and any dividends or distributions paid to the non-controlling interests.

If a transaction results in the acquisition of all, or part, of a non-controlling interest in a consolidated subsidiary, the acquisition of the non-controlling interest is accounted for as an equity transaction. No gain or loss is recognized in net earnings or comprehensive income as a result of changes in the non-controlling interest, unless a change results in the loss of control by the Company.

1. Significant accounting policies (continued)

(s) Non-controlling interests (continued)

Certain of the Company's U.S. based wind and solar businesses are organized as limited liability corporations ("LLCs") and partnerships and have non-controlling membership equity investors ("tax equity partnership units", or "Tax Equity Investors"), which are entitled to allocations of earnings, tax attributes and cash flows in accordance with contractual agreements. These LLCs and partnership agreements have liquidation rights and priorities that are different from the underlying percentage ownership interests. In those situations, simply applying the percentage ownership interest to U.S. GAAP net income in order to determine earnings or losses would not accurately represent the income allocation and cash flow distributions that will ultimately be received by the investors. As such, the share of earnings attributable to the non-controlling interest holders in these entities is calculated using the Hypothetical Liquidation at Book Value ("HLBV") method of accounting (note 17).

The HLBV method uses a balance sheet approach. A calculation is prepared at each balance sheet date to determine the amount that Tax Equity Investors would receive if an equity investment entity were to liquidate all of its assets and distribute that cash to the investors based on the contractually defined liquidation priorities. The difference between the calculated liquidation distribution amounts at the beginning and the end of the reporting period is the Tax Equity Investors' share of the earnings or losses from the investment for that period. Due to certain mandatory liquidation provisions of the LLC and partnership agreements, this could result in a net loss to APUC's consolidated results in periods in which the Tax Equity Investors report net income. The calculation varies in its complexity depending on the capital structure and the tax considerations of the investments.

Equity instruments subject to redemption upon the occurrence of uncertain events not solely within APUC's control are classified as temporary equity and presented as redeemable non-controlling interests on the consolidated balance sheets. The Company records temporary equity at issuance based on cash received less any transaction costs. As needed, the Company reevaluates the classification of its redeemable instruments, as well as the probability of redemption. If the redemption amount is probable or currently redeemable, the Company records the instruments at their redemption value. Increases or decreases in the carrying amount of a redeemable instrument are recorded within deficit. When the redemption feature lapses or other events cause the classification of an equity instrument as temporary equity to be no longer required, the existing carrying amount of the equity instrument is reclassified to permanent equity at the date of the event that caused the reclassification.

(t) Recognition of revenue

The Company accounts for revenue in accordance with ASC Topic 606, *Revenue from Contracts with Customers*, which was adopted on January 1, 2018 using the modified retrospective method, applied to contracts that were not completed at the date of initial application. The adoption of the new standard resulted in an adjustment of $2,488 or $1,860 net of taxes to increase opening retained earnings for previously deferred revenue related to the Empire fiber business.

Revenue is recognized when control of the promised goods or services is transferred to the Company's customers in an amount that reflects the consideration the Company expects to be entitled to in exchange for those goods or services.

Refer to note 21, "Segmented information" for details of revenue disaggregation by business units.

1. Significant accounting policies (continued)

(t) Recognition of revenue (continued)

Regulated Services Group revenue

Regulated Services Group revenues consist primarily of the distribution of electricity, natural gas, and water.

Revenue related to utility electricity and natural gas sales and distribution is recognized over time as the energy is delivered. At the end of each month, the electricity and natural gas delivered to the customers from the date of their last meter read to the end of the month is estimated and the corresponding unbilled revenue is recorded. These estimates of unbilled revenue and sales are based on the ratio of billable days versus unbilled days, amount of electricity or natural gas procured during that month, historical customer class usage patterns, weather, line loss, unaccounted-for gas and current tariffs. Unbilled receivables are typically billed within the next month. Some customers elect to pay their bill on an equal monthly plan. As a result, in some months cash is received in advance of the delivery of electricity. Deferred revenue is recorded for that amount. The amount of revenue recognized in the period from the balance of deferred revenue is not significant.

Water reclamation and distribution revenue is recognized over time when water is processed or delivered to customers. At the end of each month, the water delivered and wastewater collected from the customers from the date of their last meter read to the end of the month are estimated and the corresponding unbilled revenue is recorded. These estimates of unbilled revenue are based on the ratio of billable days versus unbilled days, amount of water procured and collected during that month, historical customer class usage patterns and current tariffs. Unbilled receivables are typically billed within the next month.

On occasion, a utility is permitted to implement new rates that have not been formally approved by the regulatory commission, which are subject to refund. The Company recognizes revenue based on the interim rate and, if needed, establishes a reserve for amounts that could be refunded based on experience for the jurisdiction in which the rates were implemented.

Revenue for certain of the Company’s regulated utilities is subject to alternative revenue programs approved by their respective regulators. Under these programs, the Company charges approved annual delivery revenue on a systematic basis over the fiscal year. As a result, the difference between delivery revenue calculated based on metered consumption and approved delivery revenue is disclosed as alternative revenue in note 21, "Segmented information" and is recorded as a regulatory asset or liability to reflect future recovery or refund, respectively, from customers (note 7). The amount subsequently billed to customers is recorded as a recovery of the regulatory asset.

Renewable Energy Group revenue

Renewable Energy Group's revenue consists primarily of the sale of electricity, capacity, and renewable energy credits.

Revenue related to the sale of electricity is recognized over time as the electricity is delivered. The electricity represents a single performance obligation that represents a promise to transfer to the customer a series of distinct goods that are substantially the same and that have the same pattern of transfer to the customer.

Revenues related to the sale of capacity are recognized over time as the capacity is provided. The nature of the promise to provide capacity is that of a stand-ready obligation. The capacity is generally expressed in monthly volumes and prices. The capacity represents a single performance obligation that represents a promise to transfer to the customer a series of distinct services that are substantially the same and that have the same pattern of transfer to the customer.

Qualifying renewable energy projects receive renewable energy credits (“RECs”) and solar renewable energy credits (“SRECs”) for the generation and delivery of renewable energy to the power grid. The energy credit certificates represent proof that 1 MW of electricity was generated from an eligible energy source. The RECs and SRECs can be traded and the owner of the RECs or SRECs can claim to have purchased renewable energy. RECs and SRECs are primarily sold under fixed contracts, and revenue for these contracts is recognized at a point in time, upon generation of the associated electricity. Any RECs or SRECs generated above contracted amounts are held in inventory, with the offset recorded as a decrease in operating expenses.

1. Significant accounting policies (continued)

(t) Recognition of revenue (continued)

Renewable Energy Group revenue (continued)

The Company has elected to apply the invoicing practical expedient to the electricity and capacity in the Renewable Energy Group contracts. The Company does not disclose the value of unsatisfied performance obligations for these contracts as revenue is recognized at the amount to which the Company has the right to invoice for services performed.

Revenue is recorded net of sales taxes.

(u) Foreign currency translation

APUC's reporting currency is the U.S. dollar. Within these consolidated financial statements, the Company denotes any amounts denominated in Canadian dollars with "C$" immediately prior to the stated amount.

The Company's Canadian operations are determined to have the Canadian dollar as their functional currency since the preponderance of operating, financing and investing transactions are denominated in Canadian dollars. The financial statements of these operations are translated into U.S. dollars using the current rate method, whereby assets and liabilities are translated at the rate prevailing at the balance sheet date, and revenue and expenses are translated using average rates for the period. Unrealized gains or losses arising as a result of the translation of the financial statements of these entities are reported as a component of OCI and are accumulated in a component of equity on the consolidated balance sheets, and are not recorded in income unless there is a complete or substantially complete sale or liquidation of the investment.

Subsequent to year-end, effective January 1, 2020, the functional currency of APUC, the non-consolidated parent entity, changed from the Canadian dollar to the U.S. dollar based on a balance of facts taking into consideration its operating, financing and investing activities. As a result of the entity's change of functional currency, changes were made to certain hedging relationships to mitigate the remaining Canadian dollar risk.

(v) Income taxes

Income taxes are accounted for using the asset and liability method. Deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of assets and liabilities and their respective tax bases. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. A valuation allowance is recorded against deferred tax assets to the extent that it is considered more likely than not that the deferred tax asset will not be realized. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in earnings in the period that includes the date of enactment (note 18). Investment tax credits for the rate regulated operations are deferred and amortized as a reduction to income tax expense over the estimated useful lives of the properties. Investment tax credits along with other income tax credits in the non-regulated operations are treated as a reduction to income tax expense in the year the credit arises.

The organizational structure of APUC and its subsidiaries is complex and the related tax interpretations, regulations and legislation in the tax jurisdictions in which they operate are continually changing. As a result, there can be tax matters that have uncertain tax positions. The Company recognizes the effect of income tax positions only if those positions are more likely than not of being sustained. Recognized income tax positions are measured at the largest amount that is greater than 50% likely of being realized. Changes in recognition or measurement are reflected in the period in which the change in judgment occurs.

(w) Financial instruments and derivatives

Accounts receivable and notes receivable are measured at amortized cost. Long-term debt and Series C preferred shares are measured at amortized cost using the effective interest method, adjusted for the amortization or accretion of premiums or discounts.

1. Significant accounting policies (continued)

(w) Financial instruments and derivatives (continued)

Transaction costs that are directly attributable to the acquisition of financial assets are accounted for as part of the asset's carrying value at inception. Transaction costs related to a recognized debt liability are presented in the consolidated balance sheets as a direct deduction from the carrying amount of that debt liability, consistent with debt discounts and premiums. Costs of arranging the Company's revolving credit facilities and intercompany loans are recorded in other assets. Deferred financing costs, premiums and discounts on long-term debt are amortized using the effective interest method while deferred financing costs relating to the revolving credit facilities and intercompany loans are amortized on a straight-line basis over the term of the respective instrument.

The Company uses derivative financial instruments as one method to manage exposures to fluctuations in exchange rates, interest rates and commodity prices. APUC recognizes all derivative instruments as either assets or liabilities on the consolidated balance sheets at their respective fair values. The fair value recognized on derivative instruments executed with the same counterparty under a master netting arrangement are presented on a gross basis on the consolidated balance sheets. The amounts that could net settle are not significant. The Company applies hedge accounting to some of its financial instruments used to manage its foreign currency risk, interest rate risk and price risk exposures associated with sales of generated electricity.

For derivatives designated in a cash flow hedge relationship, the change in fair value is recognized in OCI. The amount recognized in AOCI is reclassified to earnings in the same period as the hedged cash flows affect earnings under the same line item in the consolidated statements of operations as the hedged item. If the hedging instrument no longer meets the criteria for hedge accounting, expires or is sold, terminated, exercised, or the designation is revoked, then hedge accounting is discontinued prospectively. The amount remaining in AOCI is transferred to the consolidated statements of operations in the same period that the hedged item affects earnings. If the forecasted transaction is no longer expected to occur, then the balance in AOCI is recognized immediately in earnings.

Foreign currency gain or loss on derivative or financial instruments designated as a hedge of the foreign currency exposure of a net investment in foreign operations that are effective as a hedge are reported in the same manner as the translation adjustment (in OCI) related to the net investment.

The Company's electric distribution and thermal generation facilities enter into power and gas purchase contracts for load serving and generation requirements. These contracts meet the exemption for normal purchase and normal sales and, as such, are not required to be recorded at fair value as derivatives and are accounted for on an accrual basis. Counterparties are evaluated on an ongoing basis for non-performance risk to ensure it does not impact the conclusion with respect to this exemption.

(x) Fair value measurements

The Company utilizes valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs to the extent possible. The Company determines fair value based on assumptions that market participants would use in pricing an asset or liability in the principal or most advantageous market. When considering market participant assumptions in fair value measurements, the following fair value hierarchy distinguishes between observable and unobservable inputs, which are categorized in one of the following levels:

- Level 1 Inputs: Unadjusted quoted prices in active markets for identical assets or liabilities accessible to the reporting entity at the measurement date.
- Level 2 Inputs: Other than quoted prices included in level 1, inputs that are observable for the asset or liability, either directly or indirectly, for substantially the full term of the asset or liability.
- Level 3 Inputs: Unobservable inputs for the asset or liability used to measure fair value to the extent that observable inputs are not available, thereby allowing for situations in which there is little, if any, market activity for the asset or liability at the measurement date.

(y) Commitments and contingencies

Liabilities for loss contingencies arising from environmental remediation, claims, assessments, litigation, fines, penalties and other sources are recorded when it is probable that a liability has been incurred and the amount can be reasonably estimated. Legal costs incurred in connection with loss contingencies are expensed as incurred.

1. Significant accounting policies (continued)

(z) Use of estimates

The preparation of financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of these consolidated financial statements and the reported amounts of revenue and expenses during the year. Actual results could differ from those estimates. During the years presented, management has made a number of estimates and valuation assumptions, including the useful lives and recoverability of property, plant and equipment, intangible assets and goodwill; the recoverability of notes receivable and long-term investments; the recoverability of deferred tax assets; assessments of unbilled revenue; pension and OPEB obligations; timing effect of regulated assets and liabilities; contingencies related to environmental matters; the fair value of assets and liabilities acquired in a business combination; and the fair value of financial instruments. These estimates and valuation assumptions are based on present conditions and management's planned course of action, as well as assumptions about future business and economic conditions. Should the underlying valuation assumptions and estimates change, the recorded amounts could change by a material amount.

2. Recently issued accounting pronouncements

(a) Recently adopted accounting pronouncements

The FASB issued accounting standards update ("ASU") 2018-15, *Intangibles — Goodwill and Other Internal-Use Software (Subtopic 350-40): Customer's Accounting for Implementation Costs Incurred in a Cloud Computing Arrangement that is a Service Contract* to provide additional guidance to address diversity in practice. This update aligns the requirements for capitalizing implementation costs incurred in a hosting arrangement that is a service contract with the requirements for capitalizing implementation costs incurred to develop or obtain internal-use software. The Company adopted this update prospectively as at the beginning of the third quarter. There were no significant impacts to the consolidated financial statements as a result of the adoption of this update.

The FASB issued ASU 2018-16, *Derivatives and Hedging (Topic 815): Inclusion of the Secured Overnight Financing Rate ("*SOFR*") Overnight Index Swap ("*OIS*") Rate as a Benchmark Interest Rate for Hedge Accounting Purposes* to identify a suitable alternative to the U.S. dollar LIBOR that is more firmly based on actual transactions in a robust market. This update permits the use of the OIS rate based on SOFR as a U.S. benchmark interest rate for hedge accounting purposes. This update was adopted concurrently with ASU 2017-12. The Company will follow the pronouncements prospectively for qualifying new or redesignated hedging relationships.

The FASB issued ASU 2018-07, *Compensation — Stock Compensation (Topic 718): Improvements to Non-employee Share-Based Payment Accounting* to expand the scope of Topic 718 to include share-based payment transactions for acquiring goods and services from non-employees. This update changes the measurement basis and date of non-employee share-based payment awards and also makes amendments to how to measure non-employee awards with performance conditions. The adoption of this update in 2019 had no impact on the Company's consolidated financial statements.

The FASB issued ASU 2017-12, *Derivatives and Hedging (Topic 815): Targeted Improvements to Accounting for Hedging Activities*, to improve the financial reporting of hedging relationships to better portray the economic results of an entity's risk management activities in its financial statements. The update also makes certain targeted improvements to simplify the application of the hedge accounting guidance. The FASB also issued ASU 2019-04 that contains further codification improvements to ASU 2017-12. The adoption of these updates in 2019 resulted in a reclassification of $186 from retained earnings to accumulated other comprehensive income for previous hedge ineffectiveness recognized in earnings for outstanding hedging contracts. The Company has also made certain amendments and simplifications to hedge effectiveness testing procedures and documentation to be followed prospectively where applicable in accordance with the pronouncements in the update.

2. Recently issued accounting pronouncements (continued)

(a) Recently adopted accounting pronouncements (continued)

The FASB issued ASU 2017-11, *Earnings Per Share (Topic 260); Distinguishing Liabilities from Equity (Topic 480); Derivatives and Hedging (Topic 815): (Part I) Accounting for Certain Financial Instruments with Down Round Features, (Part II) Replacement of the Indefinite Deferral for Mandatorily Redeemable Financial Instruments of Certain Nonpublic Entities and Certain Mandatorily Redeemable Noncontrolling Interests with a Scope Exception* to address narrow issues with applying U.S. GAAP for certain financial instruments with characteristics of liabilities and equity. The adoption of this update in 2019 had no impact on the consolidated financial statements.

The FASB issued ASU 2016-02, *Leases (Topic 842)* to increase transparency and comparability among organizations utilizing leases. This ASU requires lessees to recognize the assets and liabilities arising from all leases on the balance sheet, but the effect of leases in the statement of operations and the statement of cash flows is largely unchanged. The FASB also issued subsequent amendments to ASC 842 that provide further practical expedients as well as codification clarifications and improvements. The adoption of this new lease standard in 2019 using a modified retrospective approach resulted in an adjustment of $8,295 to right-of-use assets and operating lease liabilities included in other long-term liabilities on the consolidated balance sheets, with no restatement of the comparative period.

The Company implemented new processes and procedures for the identification, analysis, and measurement of new lease contracts. A new software solution was implemented to assist with contract management, information tracking, and measurement as it relates to the new standard. The Company elected the following practical expedients as part of its adoption:

1. "Package of three" practical expedient that permits the Company not to reassess the scope, classification and initial direct costs of its expired and existing leases;
2. Land easements practical expedient that permits the Company not to reassess the accounting for land easements previously not accounted for under Leases ASC 840; and
3. Hindsight practical expedient that allows the Company to use hindsight in determining the lease term for existing contracts.

In addition, the Company made an accounting policy election to not recognize a lease liability or right-of-use asset on its consolidated balance sheets for short-term leases (lease term less than 12 months).

(b) Recently issued accounting guidance not yet adopted

The FASB issued ASU 2020-01, *Investments - Equity Securities (Topic 321), Investments — Equity Method and Joint Ventures (Topic 323), and Derivatives and Hedging (Topic 815): Clarifying the Interactions between Topic 321, Topic 323, and Topic 815* to reduce diversity in practice and increase comparability of accounting for certain transactions. The amendments clarify when to consider observable price changes for the measurement of certain equity securities without a readily determinable fair value. They also clarify the scope of forward contracts and purchased options on these certain securities. The amendments in this update are effective for fiscal years beginning after December 15, 2020, and interim periods within those years. Early adoption is permitted, including early adoption in any interim period. The Company currently does not have any transactions that would be within the scope of this update but will continue to assess the impact of this update in the future.

The FASB issued ASU 2019-12, *Income Taxes (Topic 740): Simplifying the Accounting for Income Taxes* as part of its initiative to reduce complexity in the accounting standards. The amendments remove certain exceptions to the general principles in Topic 740 and improve consistent application for other areas of Topic 740 by clarifying and amending existing guidance. The amendments in this update are effective for fiscal years beginning after December 15, 2020, and interim periods within those years. Early adoption is permitted, but all amendments must be early adopted simultaneously. The Company is currently assessing the impact of this update.

2. Recently issued accounting pronouncements (continued)

(b) Recently issued accounting guidance not yet adopted (continued)

The FASB issued ASU 2018-18, *Collaborative Arrangements (Topic 808): Clarifying the Interaction between Topic 808 and Topic 606* to reduce diversity in practice on how entities account for transactions on the basis of different views of the economics of a collaborative arrangement. The update clarifies that the arrangement should be accounted for under ASC 606 when a participant is a customer in the context of a unit of account, adds unit of account guidance in ASC 808 that is consistent with ASC 606, and precludes the recognition of revenue from a collaborative arrangement with ASC 606 revenue if the participant is not directly related to sales to third parties. The amendments in this update are effective for fiscal years beginning after December 15, 2019, and interim periods within those years. The Company does not expect a significant impact on its consolidated financial statements as a result of the adoption of this update.

The FASB issued ASU 2018-17, *Consolidation (Topic 810): Targeted Improvements to Related Party Guidance for Variable Interest Entities* to improve general purpose financial reporting. The update clarifies that indirect interests held through related parties in common control arrangements should be considered on a proportional basis for determining whether fees paid to decision makers and service providers are variable interests. The amendments in the update are effective for fiscal years beginning after December 15, 2019 and interim periods within those fiscal years. The amendments are required to be applied retrospectively with a cumulative-effect adjustment to retained earnings. The Company does not expect a significant impact on its consolidated financial statements as a result of the adoption of this update.

The FASB issued ASU 2017-04, *Business Combinations (Topic 350): Intangibles — Goodwill and Other (Topic 350): Simplifying the Test for Goodwill Impairment*. The update is intended to simplify how an entity is required to test goodwill for impairment by eliminating Step 2 from the goodwill impairment test. Step 2 measures a goodwill impairment loss by comparing the implied fair value of a reporting unit's goodwill with the carrying amount of that goodwill. The standard is effective for fiscal years and interim periods beginning after December 15, 2019. The Company does not expect a significant impact on its consolidated financial statements as a result of the adoption of this update.

The FASB issued ASU 2016-13, *Financial Instruments — Credit Losses (Topic 326): Measurement of Credit Losses on Financial Instruments* to provide financial statement users with more decision-useful information about the expected credit losses on financial instruments and other commitments to extend credit held by a reporting entity at each reporting date. To achieve this objective, the amendments in this update replace the incurred loss impairment methodology in current U.S. GAAP with a methodology that reflects expected credit losses. The standard is effective for fiscal years and interim periods beginning after December 15, 2019. The FASB issued codification improvements to ASC Topic 326 in ASU 2018-19 to provide guidance on scoping of operating lease assets and further specific clarifications and corrections in ASU 2019-04 and ASU 2019-11. The FASB issued further updates to Topic 326 in ASU 2019-05 and ASU 2020-02 to provide transition relief that allows companies to irrevocably elect the fair value option for certain instruments held at amortized cost, and to provide certain updates to the SEC paragraphs of the topic. The Company is finalizing its analysis on the impact of adoption of this standard on its consolidated financial statements. The Company does not expect a significant impact on its consolidated financial statements as a result of the adoption of this update.

(in thousands of U.S. dollars, except as noted and per share amounts)

3. Business acquisitions and development projects

(a) Acquisition of Enbridge Gas New Brunswick Limited Partnership & St. Lawrence Gas Company Inc.

The Company completed the acquisition of New Brunswick Gas on October 1, 2019, and St. Lawrence Gas Company, Inc. ("St. Lawrence Gas") on November 1, 2019. New Brunswick Gas is a regulated utility that provides natural gas. The purchase price is approximately $256,011 (C$339,036). St. Lawrence Gas is a regulated utility that provides natural gas in northern New York State. The total purchase price for the transaction is $61,820, and subject to certain closing adjustments.

The costs related to the acquisitions have been expensed through the consolidated statements of operations.

The following table summarizes the preliminary allocation of the assets acquired and liabilities assumed at the acquisition date:

	New Brunswick Gas	St. Lawrence Gas
Working capital	$ 8,782	$ 3,403
Property, plant and equipment	137,668	49,936
Goodwill	56,054	20,259
Regulatory assets	94,827	3,562
Deferred income tax assets, net	—	1,614
Other assets	125	6,418
Regulatory liabilities	(2,076)	(10,412)
Pension and post-employment benefits	—	(12,376)
Deferred income tax liability, net	(38,053)	—
Other liabilities	(1,316)	(584)
Total net assets acquired	$ 256,011	$ 61,820
Cash and cash equivalent	7,248	1,225
Total net assets acquired, net of cash and cash equivalent	$ 248,763	$ 60,595

The determination of the fair value of assets acquired and liabilities assumed is based upon management's preliminary estimates and certain assumptions. Due to the timing of the acquisitions, the Company has not finalized the fair value measurements. The Company will continue to review information and perform further analysis prior to finalizing the fair value of the consideration paid and the fair value of assets acquired and liabilities assumed.

Goodwill represents the excess of the purchase price over the aggregate fair value of net assets acquired. The contributing factors to the amount recorded as goodwill include future growth, potential synergies, and cost savings in the delivery of certain shared administrative and other services.

Property, plant and equipment, exclusive of computer software, are amortized in accordance with regulatory requirements over the estimated useful life of the assets using the straight-line method. The weighted average useful life of New Brunswick Gas and St. Lawrence Gas' assets is 47 years and 49 years, respectively.

3. Business acquisitions and development projects (continued)

(b) Acquisition of Turquoise Solar Facility

Liberty Utilities (Turquoise Holdings) LLC (“Turquoise Holdings”) is owned by Liberty Utilities (Calpeco Electric) LLC ("Calpeco Electric System"). The 10 MWac solar generating facility is located in Washoe County, Nevada ("Turquoise Solar Facility"). On May 24, 2019, a tax equity agreement was executed. The Class A partnership units are owned by a third-party tax equity investor who funded $1,403 on the execution date and $2,000 on December 31, 2019. The final instalments are expected to be made in 2020. With its interest, the tax equity investor will receive the majority of the tax attributes associated with the Turquoise Solar Facility. Because the Class A tax equity investor has the right to withdraw from Turquoise Holdings and require the Company to redeem its remaining interests for cash, the Company accounts for this interest as “Redeemable non-controlling interest” outside of permanent equity on the consolidated balance sheets (note 17). Redemption is not considered probable as of December 31, 2019.

On December 31, 2019, as the Turquoise Solar Facility was placed in service, Turquoise Holdings obtained control of the property, plant and equipment for a total purchase price of $20,830.

(c) Agreement to acquire Mid-West Wind Development Project

The Empire District Electric Company ("Empire Electric System"), a wholly owned subsidiary of the Company, entered into purchase agreements to acquire, once completed, three wind farms generating up to 600 MW of wind energy located in Barton, Dade, Lawrence, and Jasper Counties in Missouri ("Missouri Wind Projects") and in Neosho County, Kansas ("Kansas Wind Project"). The agreements contain development milestones and termination provisions that primarily apply prior to the commencement of construction. Total costs are estimated at $1,100,000 and the acquisitions are anticipated to close following completion of the respective projects. These assets, net of third-party tax equity investment, are expected to be included in the rate base of the Empire Electric System.

In November 2019, Liberty Utilities Co, a wholly owned subsidiary of the Company, acquired an interest in the entities that own the two Missouri Wind Projects and, in partnership with a third-party developer, will continue development and construction of such projects until they are acquired by the Empire Electric System following completion. As part of the investment in the joint ventures, Liberty Utilities Co. entered into guarantee agreements for obligations under letters of credit, engineering and procurement contracts, and turbine supply agreements for the two projects. The Company accounts for its interest in these two projects using the equity method (note 8(d)).

In November 2019, a tax equity agreement was executed for the Kansas Wind Project. The Class A partnership units will be owned by two third-party tax equity investors who have committed to fund on a future date. With their interests, the tax equity investors will receive the majority of the tax attributes associated with the Kansas Wind Project. Initial tax equity funding is expected to be received in Q1 2021.

(d) Agreement to acquire New York American Water

On November 20, 2019, the Company entered into an agreement to acquire American Water's regulated operations in the State of New York ("New York American Water"). New York American Water is a regulated water and wastewater utility serving customers across seven counties in southeastern New York. The total purchase price for the transaction is approximately $608,000, subject to certain closing adjustments. The transaction is expected to close sometime in 2021 and remains subject to regulatory approval and other typical closing conditions.

(e) Agreement to acquire Bermuda Electric Light Company

On June 3, 2019, the Company entered into an agreement to acquire the Ascendant Group Limited ("Ascendant"), parent company of Bermuda Electric Light Company. Bermuda Electric Light Company is the sole electric utility providing regulated electrical generation, transmission and distribution services to Bermuda's residents and businesses. The total purchase price for the transaction is approximately $365,000. Closing of the transaction remains subject to shareholder and regulatory approvals and is expected in 2020.

(in thousands of U.S. dollars, except as noted and per share amounts)

3. Business acquisitions and development projects (continued)

(f) Approval to acquire the Perris Water Distribution System

On August 10, 2017, the Company agreed to acquire two water distribution systems serving customers from the City of Perris, California. The anticipated purchase price of $11,500 is expected to be established as rate base during the regulatory approval process. The City of Perris residents voted to approve the sale on November 7, 2017. The Regulated Services Group filed an application requesting approval for the acquisition of the assets of the water utilities with the California Public Utility Commission on May 8, 2018. Final approval is expected in 2020.

(g) Great Bay Solar Facilities

The Great Bay Solar I and II Facilities are 75 and 40 MWac solar powered generating facilities in Somerset County, Maryland. Commercial operations as defined by the power purchase agreement was reached for all sites at the Great Bay Solar I Facility by March 29, 2018. As of December 31, 2019, one site at the Great Gay Solar II Facility has been fully synchronized with the power grid, while the remaining site is expected to be placed in service in early 2020.

The Great Bay Solar I Facility is controlled by a subsidiary of APUC (Great Bay Holdings, LLC). The Class A partnership units are owned by a third-party tax equity investor who funded $42,750 in 2017 with the remaining amount of $15,250 received in 2018. Through its partnership interest, the tax equity investor will receive the majority of the tax attributes associated with the project. The Company accounts for this interest as "Non-controlling interest" on the consolidated balance sheets.

The Great Bay Solar II Facility is controlled by Great Bay Holdings, LLC. Liberty Utilities (America) Holdco, a subsidiary of APUC, is the tax equity investor for the facility and contributed initial funding of $11,281 in December 2019. The facility generated an investment tax credit of $8,526 during the year, which was recorded by the Company as a reduction to income tax expense in the consolidated statement of operations.

4. Accounts receivable

Accounts receivable as of December 31, 2019 include unbilled revenue of $80,295 (2018 - $79,742) from the Company's regulated utilities. Accounts receivable as of December 31, 2019 are presented net of allowance for doubtful accounts of $4,939 (2018 - $5,281).

5. Property, plant and equipment

Property, plant and equipment consist of the following:

2019

	Cost	Accumulated depreciation	Net book value
Generation	$ 2,816,611	$ 540,118	$ 2,276,493
Distribution and transmission	4,988,297	598,449	4,389,848
Land	74,517	—	74,517
Equipment and other	94,583	47,541	47,042
Construction in progress			
Generation	140,235	—	140,235
Distribution and transmission	303,529	—	303,529
	$ 8,417,772	$ 1,186,108	$ 7,231,664

(in thousands of U.S. dollars, except as noted and per share amounts)

5. Property, plant and equipment (continued)

2018

	Cost	Accumulated depreciation	Net book value
Generation	$ 2,470,279	$ 450,230	$ 2,020,049
Distribution and transmission	4,455,935	521,236	3,934,699
Land	73,773	—	73,773
Equipment and other	88,757	41,295	47,462
Construction in progress			
Generation	104,996	—	104,996
Distribution and transmission	212,579	—	212,579
	$ 7,406,319	$ 1,012,761	$ 6,393,558

Generation assets include cost of $109,653 (2018 - $104,107) and accumulated depreciation of $39,638 (2018 - $34,916) related to facilities under financing lease or owned by consolidated VIEs. Depreciation expense of facilities under finance leases was $1,615 (2018 - $1,987).

Distribution and transmission assets include the following:

- Cost of $1,450,946 (2018 - $1,383,960) and accumulated depreciation of $97,080 (2018 - $69,960) related to regulated generation and transmission assets.
- Cost of $514,709 (2018 - $503,664) and accumulated depreciation of $31,349 (2018 - $21,697) related to commonly owned facilities (note 1(k)). Total expenditures incurred on these facilities for the year ended December 31, 2019 were $69,210 (2018 - $75,427).
- Cost of $3,076 (2018 - $3,076) and accumulated depreciation of $1,003 (2018 - $669) related to assets under finance lease.
- Expansion costs of $1,000 on which the Company does not currently earn a return.

For the year ended December 31, 2019, contributions received in aid of construction of $7,137 (2018 - $6,057) have been credited to the cost of the assets.

Interest and AFUDC capitalized to the cost of the assets in 2019 and 2018 are as follows:

	2019	2018
Interest capitalized on non-regulated property	**$ 4,538**	$ 2,268
AFUDC capitalized on regulated property:		
Allowance for borrowed funds	**2,745**	1,684
Allowance for equity funds	**4,896**	2,728
Total	**$ 12,179**	$ 6,680

6. Intangible assets and goodwill

Intangible assets consist of the following:

2019	Cost	Accumulated amortization	Net book value
Power sales contracts	**$ 56,206**	**$ 38,931**	**$ 17,275**
Customer relationships	**26,797**	**10,104**	**16,693**
Interconnection agreements	**14,827**	**1,179**	**13,648**
	$ 97,830	**$ 50,214**	**$ 47,616**

(in thousands of U.S. dollars, except as noted and per share amounts)

6. Intangible assets and goodwill (continued)

2018		Cost		Accumulated amortization		Net book value
Power sales contracts	$	60,775	$	36,063	$	24,712
Customer relationships		26,795		9,476		17,319
Interconnection agreements		13,847		884		12,963
	$	101,417	$	46,423	$	54,994

Estimated amortization expense for intangible assets for the next year is $2,018, $2,190 in year two, $2,350 in year three, $1,910 in year four and $1,780 in year five.

All goodwill pertains to the Regulated Services Group.

Balance, December 31, 2018 and 2017	**$**	**954,282**
Business acquisitions (note 3(a))		**76,313**
Foreign exchange		**1,101**
Balance, December 31, 2019	**$**	**1,031,696**

7. Regulatory matters

The operating companies within the Regulated Services Group are subject to regulation by the public utility commissions of the states and provinces in which they operate. The respective public utility commissions have jurisdiction with respect to rate, service, accounting policies, issuance of securities, acquisitions and other matters. These utilities operate under cost-of-service regulation as administered by these authorities. The Company's regulated utility operating companies are accounted for under the principles of ASC 980. Under ASC 980, regulatory assets and liabilities that would not be recorded under U.S. GAAP for non-regulated entities are recorded to the extent that they represent probable future revenue or expenses associated with certain charges or credits that will be recovered from or refunded to customers through the rate setting process.

During 2019, the Company completed the acquisition of New Brunswick Gas and St. Lawrence Gas, operating public utilities engaged in the distribution of natural gas in the Province of New Brunswick and the state of New York, respectively. New Brunswick Gas is subject to regulation by the New Brunswick Energy and Utilities Board. St. Lawrence Gas is subject to regulation by the New York Public Service Commission. In general, the commissions set rates at a level that allows the utilities to collect total revenues or revenue requirements equal to the cost of providing service, plus an appropriate return on invested capital.

At any given time, the Company can have several regulatory proceedings underway. The financial effects of these proceedings are reflected in the consolidated financial statements based on regulatory approval obtained to the extent that there is a financial impact during the applicable reporting period. The following regulatory proceedings were recently completed:

Utility	State	Regulatory proceeding type	Annual revenue increase	Effective date
Peach State Gas System	Georgia	Georgia Rate Adjustment mechanism	$2,367	February 1, 2019
New England Natural Gas System	Massachusetts	Gas System Enhancement Plan	$2,413	May 1, 2019
Empire Electric System	Kansas	General Rate Review	$2,449	August 1, 2019
Empire Electric System	Oklahoma	General Rate Review	$1,400	October 1, 2019
CalPeco Electric System	California	Catastrophic Events Memorandum Account	$3,525	January 1, 2020

(in thousands of U.S. dollars, except as noted and per share amounts)

7. Regulatory matters (continued)

Regulatory assets and liabilities consist of the following:

		2019		2018
Regulatory assets				
Environmental remediation (a)	**$**	**82,300**	$	82,295
Pension and post-employment benefits (b)		**143,292**		135,580
Income taxes (c)		**71,506**		34,822
Debt premium (d)		**42,150**		48,847
Fuel and commodity cost adjustments (e)		**23,433**		26,310
Rate adjustment mechanism (f)		**69,121**		37,202
Clean Energy and other customer programs (g)		**26,369**		24,095
Deferred capitalized costs (h)		**38,833**		13,986
Asset retirement obligation (i)		**23,841**		21,048
Long-term maintenance contract (j)		**13,264**		8,283
Rate review costs (k)		**6,695**		6,164
Other		**19,083**		21,463
Total regulatory assets	**$**	**559,887**	$	460,095
Less: current regulatory assets		**(50,213)**		(59,037)
Non-current regulatory assets	**$**	**509,674**	$	401,058
Regulatory liabilities				
Income taxes (c)	**$**	**321,960**	$	323,384
Cost of removal (l)		**196,423**		193,564
Rate base offset (m)		**8,719**		10,900
Fuel and commodity costs adjustments (e)		**16,645**		21,352
Rate adjustment mechanism (f)		**10,446**		4,210
Deferred capitalized costs - fuel related (h)		**7,097**		7,258
Pension and post-employment benefits (b)		**22,256**		11,791
Other		**14,516**		15,754
Total regulatory liabilities	**$**	**598,062**	$	588,213
Less: current regulatory liabilities		**(41,683)**		(39,005)
Non-current regulatory liabilities	**$**	**556,379**	$	549,208

7. Regulatory matters (continued)

(a) Environmental remediation

Actual expenditures incurred for the clean-up of certain former gas manufacturing facilities (note 12(b)) are recovered through rates over a period of 7 years and are subject to an annual cap.

(b) Pension and post-employment benefits

As part of certain business acquisitions, the regulators authorized a regulatory asset or liability being set up for the amounts of pension and post-employment benefits that have not yet been recognized in net periodic cost and were presented as AOCI prior to the acquisition. The balance is recovered through rates over the future service years of the employees at the time the regulatory asset was set up (an average of 10 years) or consistent with the treatment of OCI under ASC 712, *Compensation Non-retirement Post-employment Benefits* and ASC 715, *Compensation Retirement Benefits* before the transfer to regulatory asset occurred. The annual movements in AOCI for Empire Electric and Gas systems' and St. Lawrence Gas system's pension and OPEB plans (note 10(a)) are also reclassified to regulatory accounts since it is probable the unfunded amount of these plans will be afforded rate recovery. Finally, the regulators have also approved tracking accounts for a number of the utilities. The amounts recorded in these accounts occur when actual expenses differ from those adopted and recovery or refunds are expected to occur in future periods.

(c) Income taxes

The income taxes regulatory assets and liabilities represent income taxes recoverable through future revenues required to fund flow-through deferred income tax liabilities and amounts owed to customers for deferred taxes collected at a higher rate than the current statutory rates.

On June 1, 2018, the State of Missouri enacted legislation that, effective for tax years beginning on or after January 1, 2020, reduces the corporate income tax rate from 6.25% to 4%, among other legislative changes. A reduction of regulatory asset and an increase to regulatory liability were recorded for excess deferred taxes probable of being refunded to customers of $15,586.

(d) Debt premium

Debt premium on acquired debt is recovered as a component of the weighted average cost of debt.

(e) Fuel and commodity cost adjustments

The revenue from the utilities includes a component that is designed to recover the cost of electricity and natural gas through rates charged to customers. To the extent actual costs of power or natural gas purchased differ from power or natural gas costs recoverable through current rates, that difference is deferred and recorded as a regulatory asset or liability on the consolidated balance sheets. These differences are reflected in adjustments to rates and recorded as an adjustment to cost of electricity and natural gas in future periods, subject to regulatory review. Derivatives are often utilized to manage the price risk associated with natural gas purchasing activities in accordance with the expectations of state regulators. The gains and losses associated with these derivatives (note 24(b)(i)) are recoverable through the commodity costs adjustment.

(f) Rate adjustment mechanism

Revenue for Calpeco Electric System, Park Water System, Peach State Gas System, New England Gas System, Midstates Natural Gas system, and EnergyNorth Natural Gas System is subject to a revenue decoupling mechanism approved by their respective regulator, which requires charging approved annual delivery revenue on a systematic basis over the fiscal year. As a result, the difference between delivery revenue calculated based on metered consumption and approved delivery revenue is recorded as a regulatory asset or liability to reflect future recovery or refund, respectively, from customers. In addition, retroactive rate adjustments for services rendered but to be collected over a period not exceeding 24 months are accrued upon approval of the Final Order. The difference between New Brunswick Gas' regulated revenues and its regulated cost of service in past years is also recorded as a regulatory asset and is recovered on a straight-line basis over the next 25 years.

(g) Clean Energy and other customer programs

The regulatory asset for Clean Energy and customer programs includes initiatives related to solar rebate applications processed and resulting rebate-related costs. The amount also includes other energy efficiency programs.

(in thousands of U.S. dollars, except as noted and per share amounts)

7. Regulatory matters (continued)

(h) Deferred capitalized costs

Deferred capitalized costs reflect deferred construction costs and fuel-related costs of specific generating facilities of the Empire Electric System. These amounts are being recovered over the life of the plants. The amount also includes capitalized operating and maintenance costs of New Brunswick Gas, and these amounts are being recovered at a rate of 2.43% annually over the next 29 years.

(i) Asset retirement obligation

Asset retirement obligations are recorded for legally required removal costs of property plant and equipment. The costs of retirement of assets as well as the on-going liability accretion and asset depreciation expense are expected to be recovered through rates.

(j) Long-term maintenance contract

To the extent actual costs of long-term maintenance incurred for one of Empire Electric System's power plants differ from the costs recoverable through current rates, that difference is deferred and recorded as a regulatory asset or liability on the consolidated balance sheets.

(k) Rate review costs

The costs to file, prosecute and defend rate review applications are referred to as rate review costs. These costs are capitalized and amortized over the period of rate recovery granted by the regulator.

(l) Cost of removal

Rates charged to customers cover for costs that are expected to be incurred in the future to retire the utility plant. A regulatory liability tracks the amounts that have been collected from customers net of costs incurred to date.

(m) Rate base offset

The regulators imposed a rate base offset that will reduce the revenue requirement at future rate proceedings. The rate base offset declines on a straight-line basis over a period of 10-16 years.

As recovery of regulatory assets is subject to regulatory approval, if there were any changes in regulatory positions that indicate recovery is not probable, the related cost would be charged to earnings in the period of such determination. The Company generally earns carrying charges on the regulatory balances related to commodity cost adjustment, retroactive rate adjustments and rate review costs.

8. Long-term investments

Long-term investments consist of the following:

	2019	2018
Long-term investments carried at fair value		
Atlantica (a)	**$ 1,178,581**	$ 814,530
AYES Canada (b)	**88,494**	—
San Antonio Water System (c)	**27,072**	—
	$ 1,294,147	$ 814,530
Other long-term investments		
Equity-method investees (d)	**$ 83,770**	$ 29,588
Development loans receivable from equity-method investees (e)	**36,204**	101,417
Other	**1,994**	4,773
Total other long-term investments	**$ 121,968**	$ 135,778
Less: current portion	**—**	(1,407)
	$ 121,968	$ 134,371

(in thousands of U.S. dollars, except as noted and per share amounts)

8. Long-term investments (continued)

Income (loss) from long-term investments from the years ended December 31, 2019 and 2018 is as follows:

	Year ended December 31	
	2019	**2018**
Fair value gain (loss) on investments carried at fair value		
Atlantica	**$ 290,740**	$ (137,957)
AYES Canada	**(6,649)**	—
San Antonio Water System	**(6,007)**	—
	$ 278,084	$ (137,957)
Dividend and interest income from investments carried at fair value		
Atlantica	**$ 69,307**	$ 39,263
AYES Canada	**25,572**	—
San Antonio Water System	**6,007**	—
	$ 100,886	$ 39,263
Other long-term investments		
Equity method loss	**(9,108)**	(3,082)
Interest and other income	**29,230**	16,958
	$ 399,092	$ (84,818)

(a) Investment in Atlantica

AAGES (AY Holdings) B.V. ("AY Holdings"), an entity controlled and consolidated by APUC, has a share ownership in Atlantica Yield plc ("Atlantica") of approximately 44.2% (December 31, 2018 - 41.5%). APUC has the flexibility, subject to certain conditions, to increase its ownership of Atlantica up to 48.5%. In 2019, the Company purchased 1,384,402 treasury shares of Atlantica for cash consideration of $30,000. In addition, 2,000,000 shares were received pursuant to a prepayment of $53,750. Subsequent to year-end, the prepayment purchase agreement settled with no material cash difference. During 2018, APUC purchased from Abengoa S.A. ("Abengoa") a 41.5% equity interest in Atlantica through two transactions for a total purchase price of $952,567, with a holdback of $40,000 of which $29,100 was settled in 2019 with the balance payable at a later date, subject to certain conditions. The Company has elected the fair value option under ASC 825, *Financial Instruments* to account for its investment in Atlantica, with changes in fair value reflected in the consolidated statements of operations.

On November 28, 2018, Abengoa-Algonquin Global Energy Solutions B.V. ("AAGES B.V."), an equity investee of the Company, obtained a three-year secured credit facility in the amount of $306,500 and subscribed to a $305,000 preference share ownership interest in AY Holdings. The subscription proceeds were distributed by AY Holdings to the Company and used by the Company to repay the $305,000 of temporary financing used for the 2018 investment in Atlantica. The AAGES B.V. secured credit facility is collateralized through a pledge of the Atlantica shares held by AY Holdings. A collateral shortfall would occur if the net obligation as defined in the agreement would equal or exceed 50% of the market value of the Atlantica shares in which case the lenders would have the right to sell Atlantica stock to eliminate the collateral shortfall. The AAGES B.V. secured credit facility is repayable on demand if Atlantica ceases to be a public company. APUC reflects the preference share ownership issued by AY Holdings as redeemable non-controlling interest held by related party (note 17).

8. Long-term investments (continued)

(b) Investment in AYES Canada

On May 24, 2019, APUC and Atlantica formed Atlantica Yield Energy Solutions Canada Inc. ("AYES Canada"), a vehicle to channel co-investment opportunities in which Atlantica holds the majority of voting rights. The first investment was Windlectric Inc. ("Windlectric"). APUC invested $91,918 (C$123,603) and Atlantica invested $4,834 (C$6,500) in AYES Canada, which in turn invested those funds in Amherst Island Partnership ("AIP"), the holding company of Windlectric.

APUC continues to control and consolidate AIP and Windlectric. The investment of $96,752 (C$130,103) by AYES Canada in AIP is presented as a non-controlling interest held by a related party (notes 16 and 17). The AIP partnership agreement has liquidation rights and priorities to each equity holder that are different from the underlying percentage ownership interests. As such, the share of earnings attributable to the non-controlling interest holder is calculated using the HLBV method of accounting. The Company incurred non-controlling interest calculated using the HLBV method of accounting of $nil and recorded distributions of $26,465 (C$34,373) during the year.

AYES Canada is considered to be a VIE based on the disproportionate voting and economic interests of the shareholders. Atlantica is considered to be the primary beneficiary of AYES Canada. Accordingly, APUC's investment in AYES Canada is considered an equity method investment. Under the AYES Canada shareholders agreement, starting in May 2020, APUC has the option to exchange approximately 3,500,000 shares of AYES Canada into ordinary shares of Atlantica on a one-for-one basis, subject to certain conditions. Consistent with the treatment of the Atlantica shares, the Company has elected the fair value option under ASC 825, *Financial Instruments* to account for its investment in AYES Canada, with changes in fair value reflected in the consolidated statements of operations. A level 3 discounted cash flow approach combined with the binomial tree approach were used to estimate the fair value of the investment. For the year, APUC recorded dividend income of $25,572 and a fair value loss of $6,649 on its investment in AYES Canada.

As at December 31, 2019, the Company's maximum exposure to loss is $88,494, which represents the fair value of the investment.

(c) San Antonio Water System

On May 1, 2019, APUC invested $17,000 by way of a secured loan into AWUSA VR Holding LLC ("AWUSA"), a wholly owned subsidiary of Abengoa. An additional amount of $5,000 plus interest is payable at a later date, subject to certain conditions. The loan is secured by AWUSA's investment in the Vista Ridge water pipeline project. The Vista Ridge water pipeline project is a 140 mile water pipeline from Burleson County, Texas, to San Antonio, Texas. Since APUC has the power to direct the activities of AWUSA and benefits from the economics of this entity, the Company consolidates AWUSA. AWUSA's 20% interest in Vista Ridge is accounted for using the equity method.

On December 30, 2019, the Company and a third-party developer each contributed C$1,500 to the capital of a new joint venture, created for the purpose of developing infrastructure investment opportunities. The Company sold its investment in AWUSA to the joint venture in exchange for a loan receivable of $30,293. A note payable to AWUSA of $13,293 was recognized by the Company upon deconsolidation of AWUSA. The Company holds an option exercisable at any time to acquire the remaining interest at a pre-agreed price. The sale was accounted for in accordance with ASC 860, *Transfers and Servicing* and no gain or loss was recognized.

The joint venture is considered to be a VIE due to insufficient equity at risk to finance its operations with additional subordinated financial support. Neither APUC nor the third-party developer is considered to be the primary beneficiary since each party holds 50% voting and economic interests. Accordingly, APUC's investment in the joint venture is considered an equity method investment. The Company has elected the fair value option under ASC 825, *Financial Instruments* to account for its investment, with changes in fair value reflected in the consolidated statements of operations. A level 3 discounted cash flow approach was used to estimate the fair value of the investment. For the year, APUC recorded interest income of $6,007 and a fair value loss of $6,007 on its investment in the joint venture.

As of December 31, 2019, the Company’s maximum exposure to loss is $27,072, which represents the fair value of the investment.

(in thousands of U.S. dollars, except as noted and per share amounts)

8. Long-term investments (continued)

(d) Equity-method investees

The Company has non-controlling interests in various partnerships and joint ventures with a total carrying value of $83,770 (2018 - $29,588) including investments in VIEs of $59,091 (2018 - $9,581).

The Company owns a 75% interest ownership in Red Lily I, an operating 26.4 MW wind facility. APUC exercises significant influence over operating and financial policies of the Red Lily I Wind Facility. Due to certain participating rights being held by the minority investor, the decisions that which most significantly impact the economic performance of the Red Lily I Wind Facility require unanimous consent. As such, the Company accounts for the partnership using the equity method.

The Company also has 50% interests in a number of wind and solar power electric development projects and infrastructure development projects. The Company holds an option to acquire the remaining 50% interest in most development projects at a pre-agreed price. Some of the development projects include AAGES, the international development platform established with Abengoa in 2018; Sugar Creek, a 202 MW wind power development project in Logan County, Illinois; Maverick, a 490 MW wind project located in Concho County, Texas; Altavista, a 80 MW solar power project located in Campbell County, Virginia, and two approximately 150 MW wind projects in southwestern Missouri.

On April 16, 2019, the Company acquired the remaining 50% interest in Windlectric which owns a 75 MW wind generating facility ("Amherst Island Wind Facility") in the Province of Ontario for $6,362. Prior to this acquisition, APUC's 50% interest in Windlectric was recorded as an equity investment. As a result of obtaining control of the facility, the transaction was treated as an asset acquisition. APUC recorded the fair value on that date for property, plant and equipment acquired of $311,175, deferred tax asset of $3,015, working capital of $14,280 and liabilities of $1,600 for asset retirement obligation assumed; and, derecognized the existing development loan between the two parties of $316,786 (note 8(e)).

Summarized combined information for APUC's investments in significant partnerships and joint ventures is as follows:

		2019		2018
Total assets	**$**	**833,791**	$	360,372
Total liabilities		**697,751**		335,331
Net assets		**136,040**		25,041
APUC's ownership interest in the entities		**63,624**		18,042
Difference between investment carrying amount and underlying equity in net assets[(a)]		**18,487**		11,048
APUC's investment carrying amount for the entities	**$**	**82,111**	$	29,090

[(a)] The difference between the investment carrying amount and the underlying equity in net assets relates primarily to interest capitalized while the projects are under construction, the fair value of guarantees provided by the Company in regards to the investments and transaction costs.

Except for AAGES BV, the development projects are considered VIEs due to the level of equity at risk and the disproportionate voting and economic interests of the shareholders. The Company has committed loan and credit support facilities with some of its equity investees. During construction, the Company is obligated to provide cash advances (note 8(e)) and credit support in amounts necessary for the continued development and construction of the equity investees' projects. As of December 31, 2019, the Company had issued letters of credit and guarantees of obligations under a security of performance for a development opportunity; wind turbine or solar panel supply agreements; engineering, procurement, and construction agreements; purchase and sale agreements; interconnection agreements; energy purchase agreements; renewable energy credit agreements; equity capital contribution agreements; landowner agreements; and bridge loan agreements. The fair value of the support provided recorded as at December 31, 2019 amounts to $9,493 (2018 - $1,682). The Company is not considered the primary beneficiary of these entities as the partners have joint control and all decisions must be unanimous. Therefore, the Company accounts for its interest in these VIEs using the equity method.

(in thousands of U.S. dollars, except as noted and per share amounts)

8. Long-term investments (continued)

(d) Equity-method investees (continued)

Summarized combined information for APUC's VIEs is as follows:

	2019	2018
APUC's maximum exposure in regards to VIEs		
Carrying amount	**$ 59,091**	$ 9,581
Development loans receivable (e)	**35,000**	101,417
Commitments on behalf of VIEs	**1,364,871**	120,669
	$ 1,458,962	$ 231,667

The majority of the amounts committed on behalf of VIEs in the above relate to wind turbine or solar panel supply agreements as well as engineering, procurement, and construction agreements.

(e) Development loans receivable from equity investees

The Company has committed loan and credit support facilities with some of its equity investees. During construction, the Company is obligated to provide cash advances and credit support (in the form of letters of credit, escrowed cash, guarantees or indemnities) in amounts necessary for the continued development and construction of the equity investees' projects. The loans bear interest at a weighted average annual rate of 7.66% (2018 - 9.90%) on outstanding principal and generally mature on the commercial operation date.

9. Long-term debt

Long-term debt consists of the following:

Borrowing type	Weighted average coupon	Maturity	Par value	2019	2018
Senior unsecured revolving credit facilities (a)	—	2023-2024	N/A	**$ 141,577**	$ 97,000
Senior unsecured bank credit facilities (b)	—	2020	N/A	**75,000**	321,807
Commercial paper (c)	—	2020	N/A	**218,000**	6,000
U.S. dollar borrowings					
Senior unsecured notes	4.09%	2020-2047	$ 1,225,000	**1,219,579**	1,218,680
Senior unsecured utility notes	6.00%	2020-2035	$ 217,000	**233,686**	240,161
Senior secured utility bonds	4.75%	2020-2044	$ 662,500	**672,337**	676,697
Canadian dollar borrowings					
Senior unsecured notes (d)	4.48%	2021-2029	C$ 950,669	**728,679**	474,764
Senior secured project notes	10.22%	2020-2027	C$ 28,503	**21,961**	22,915
				$ 3,310,819	$ 3,058,024
Subordinated U.S. dollar borrowings					
Subordinated unsecured notes (e)	6.50%	2078-2079	$ 637,500	**621,049**	278,771
				$ 3,931,868	$ 3,336,795
Less: current portion				**(225,013)**	(13,048)
				$ 3,706,855	$ 3,323,747

Short-term obligations of $377,015 that are expected to be refinanced using the long-term credit facilities are presented as long-term debt.

9. Long-term debt (continued)

Long-term debt issued at a subsidiary level (project notes or utility bonds) relating to a specific operating facility is generally collateralized by the respective facility with no other recourse to the Company. Long-term debt issued at a subsidiary level whether or not collateralized generally has certain financial covenants, which must be maintained on a quarterly basis. Non-compliance with the covenants could restrict cash distributions/dividends to the Company from the specific facilities.

Recent financing activities:

(a) Senior unsecured revolving credit facilities

On October 24, 2019, the Company entered into a new $75,000 uncommitted bilateral letter of credit facility. The facility matures on October 24, 2020.

On July 12, 2019, the Company entered into a new $500,000 senior unsecured revolving bank credit facility that matures July 12, 2024. The interest rate is equal to the bankers' acceptance or LIBOR plus a credit spread. The existing C$165,000 credit facility was canceled.

On February 23, 2018, the Regulated Services Group increased commitments under its credit facility to $500,000 and extended the maturity to February 23, 2023. Concurrent with this amendment, the Regulated Services Group closed Empire's credit facility. The Regulated Services Group's credit facility will now be used as a backstop for Empire's commercial paper program and as a source of liquidity for Empire.

During 2018, the Renewable Energy Group extended the maturity of its senior unsecured revolving bank credit facility from October 6, 2022 to October 6, 2023. On February 16, 2018, the Renewable Energy Group increased availability under its revolving letter of credit facility to $200,000 and extended the maturity to January 31, 2021. Subsequent to year-end, on February 24, 2020, the Renewable Energy Group increased its uncommitted Renewable Energy LC Facility to $350,000 and extended the maturity to June 30, 2021.

(b) Senior unsecured bank credit facilities

On June 27, 2019, the Regulated Services Group extended the maturity of its $135,000 term loan to July 6, 2020. During the year, the Company repaid $60,000 of the facility.

On March 7, 2018, the Company drew $600,000 under a new term credit facility. The balance was repaid in 2018 except for a balance of $186,807, which was repaid on May 23, 2019.

(c) Commercial paper

On July 1, 2019, the Regulated Services Group established a new $500,000 commercial paper program. The amounts drawn at any time under this program may have maturities up to 270 days from the date of issuance and are expected to be replaced with new commercial paper upon maturity. This program is backstopped by the Regulated Services Group's bank credit facility.

(d) Canadian dollar senior unsecured notes

Subsequent to year-end, on February 14, 2020, the Regulated Services Group issued C$200,000 senior unsecured debentures bearing interest at 3.315% with a maturity date of February 14, 2050. The debentures are redeemable at the option of the Company at any time at a predetermined price.

On January 29, 2019, the Renewable Energy Group issued C$300,000 senior unsecured notes bearing interest at 4.60% with a maturity date of January 29, 2029. The notes were sold at a price of C$99.952 per C$100.00 principal amount. Concurrent with the financing, the Renewable Energy Group unwound and settled the related forward-starting interest rate swap on a notional bond of C$135,000 (note 24(b)(ii)).

On July 25, 2018, the Company repaid, upon its maturity, a C$135,000 unsecured note.

(e) Subordinated unsecured notes

On May 23, 2019, the Company issued $350,000 unsecured, 6.20% fixed-to-floating subordinated notes ("subordinated notes") maturing on July 1, 2079. Concurrent with the offering, the Company entered into a cross-currency swap to convert the U.S. dollar denominated coupon and principal payments from the offering into Canadian dollars.

(in thousands of U.S. dollars, except as noted and per share amounts)

9. Long-term debt (continued)

(e) Subordinated unsecured notes (continued)

Beginning on July 1, 2024, and on every quarter thereafter that the subordinated notes are outstanding (the "interest reset date") until July 1, 2029, the subordinated notes will be reset at an interest rate of the three-month LIBOR plus 4.01%, payable in arrears. In September 2019, the Company entered into forward-starting interest rate swaps to convert its variable interest rate to fixed for the period of July 1, 2024 to July 1, 2029 (note 24(b)(ii)). Beginning on July 1, 2029, and on every interest reset date until July 1, 2049, the subordinated notes will be reset at an interest rate of the three-month LIBOR plus 4.26%, payable in arrears. Beginning on July 1, 2049, and on every interest reset date until July 1, 2079, the subordinated notes will be reset at an interest rate of the three-month LIBOR plus 5.01%, payable in arrears.

The Company may elect, at its sole option, to defer the interest payable on the subordinated notes on one or more occasions for up to five consecutive years. Deferred interest will accrue, compounding on each subsequent interest payment date, until paid. Additionally, on or after July 1, 2024, the Company may, at its option, redeem the subordinated notes, at a redemption price equal to 100% of the principal amount, together with accrued and unpaid interest.

On October 17, 2018, the Company completed the issuance of $287,500 unsecured, 6.875% fixed-to-floating subordinated notes (“subordinated notes”) maturing on October 17, 2078. Beginning on October 17, 2023, and on every quarter thereafter that the subordinated notes are outstanding (the "interest reset date") until October 17, 2028, the subordinated notes will be reset at an interest rate of the three-month LIBOR plus 3.677%, payable in arrears. Beginning on October 17, 2028, and on every interest reset date until October 17, 2043, the subordinated notes will be reset at an interest rate of the three-month LIBOR plus 3.927%, payable in arrears. Beginning on October 17, 2043, and on every interest reset date until October 17, 2078, the subordinated notes will be reset at an interest rate of the three-month LIBOR plus 4.677%, payable in arrears.

The Company may elect, at its sole option, to defer the interest payable on the subordinated notes on one or more occasions for up to five consecutive years. Deferred interest will accrue, compounding on each subsequent interest payment date, until paid. Additionally, on or after October 17, 2023, the Company may, at its option, redeem the subordinated notes, at a redemption price equal to 100% of the principal amount, together with accrued and unpaid interest.

As of December 31, 2019, the Company had accrued $44,229 in interest expense (2018 - $33,822). Interest expense on the long-term debt, net of capitalized interest, in 2019 was $175,664 (2018 - $146,310).

Principal payments due in the next five years and thereafter are as follows:

2020	2021	2022	2023	2024	Thereafter	Total
$ 602,028	$ 117,513	$ 351,227	$ 97,478	$ 215,743	$ 2,547,916	$ 3,931,905

10. Pension and other post-employment benefits

The Company provides defined contribution pension plans to substantially all of its employees. The Company’s contributions for 2019 were $8,798 (2018 - $8,446).

In conjunction with the utility acquisitions, the Company assumes defined benefit pension, supplemental executive retirement plans and OPEB plans for qualifying employees in the related acquired businesses. The legacy plans of the electricity and gas utilities are non-contributory defined pension plans covering substantially all employees of the acquired businesses. Benefits are based on each employee’s years of service and compensation. The Company also provides a defined benefit cash balance pension plan covering substantially all its new employees and current employees at its water utilities, under which employees are credited with a percentage of base pay plus a prescribed interest rate credit. The OPEB plans provide health care and life insurance coverage to eligible retired employees. Eligibility is based on age and length of service requirements and, in most cases, retirees must cover a portion of the cost of their coverage.

(in thousands of U.S. dollars, except as noted and per share amounts)

10. Pension and other post-employment benefits (continued)

(a) Net pension and OPEB obligation

The following table sets forth the projected benefit obligations, fair value of plan assets, and funded status of the Company's plans as of December 31:

	Pension benefits		OPEB	
	2019	**2018**	**2019**	**2018**
Change in projected benefit obligation				
Projected benefit obligation, beginning of year	**$ 484,707**	$ 531,694	**$ 168,325**	$ 176,975
Projected benefit obligation assumed from business combination	**20,196**	—	**11,646**	—
Modifications to plans	**(7,705)**	—	**—**	—
Service cost	**12,351**	15,481	**4,587**	5,791
Interest cost	**20,222**	19,077	**7,575**	6,727
Actuarial (gain) loss	**65,443**	(29,986)	**33,605**	(14,800)
Contributions from retirees	**—**	—	**1,913**	1,878
Gain on curtailment	**—**	(1,875)	**—**	—
Medicare Part D	**—**	—	**414**	42
Benefits paid	**(30,244)**	(49,684)	**(8,848)**	(8,288)
Projected benefit obligation, end of year	**$ 564,970**	$ 484,707	**$ 219,217**	$ 168,325
Change in plan assets				
Fair value of plan assets, beginning of year	**339,099**	403,945	**115,542**	130,487
Plan assets acquired in business combination	**8,004**	—	**15,688**	—
Actual return on plan assets	**68,025**	(36,987)	**25,464**	(10,603)
Employer contributions	**22,190**	21,825	**8,628**	2,026
Medicare Part D subsidy receipts	**—**	—	**414**	42
Benefits paid	**(30,244)**	(49,684)	**(6,863)**	(6,410)
Fair value of plan assets, end of year	**$ 407,074**	$ 339,099	**$ 158,873**	$ 115,542
Unfunded status	**$ (157,896)**	$ (145,608)	**$ (60,344)**	$ (52,783)
Amounts recognized in the consolidated balance sheets consist of:				
Non-current assets (note 11)	**—**	—	**8,437**	3,161
Current liabilities	**(1,415)**	(873)	**(1,168)**	(850)
Non-current liabilities	**(156,481)**	(144,735)	**(67,613)**	(55,094)
Net amount recognized	**$ (157,896)**	$ (145,608)	**$ (60,344)**	$ (52,783)

The accumulated benefit obligation for the pension plans was $526,517 and $439,458 as of December 31, 2019 and 2018, respectively.

(in thousands of U.S. dollars, except as noted and per share amounts)

10. Pension and other post-employment benefits (continued)

(a) Net pension and OPEB obligation (continued)

Information for pension and OPEB plans with an accumulated benefit obligation in excess of plan assets:

	Pension		OPEB	
	2019	**2018**	**2019**	**2018**
Accumulated benefit obligation	**$ 504,403**	$ 439,458	**$ 202,422**	$ 163,375
Fair value of plan assets	**$ 407,074**	$ 339,099	**$ 133,711**	$ 107,430

Information for pension and OPEB plans with a projected benefit obligation in excess of plan assets:

	Pension		OPEB	
	2019	**2018**	**2019**	**2018**
Projected benefit obligation	**$ 564,971**	$ 476,791	**$ 202,422**	$ 163,375
Fair value of plan assets	**$ 407,074**	$ 339,099	**$ 133,711**	$ 107,430

In 2019, the Company merged the Empire pension plan into the Company's cash balance plan and defined benefit plans, and changed benefits for certain Empire participants. The total impact of these plan amendments resulted in a decrease to the projected benefit obligation of $7,798, which is recorded as a prior service credit in OCI.

In 2018, the Company permanently froze the accrual of benefits for participants in the Park Water System's existing pension plan. Subsequent to the effective date, these employees began accruing benefits under the Company's cash balance plan. The plan amendments resulted in a decrease to the projected benefit obligation of $1,875, which is recorded as a prior service credit in OCI.

(b) Pension and post-employment actuarial changes

Change in AOCI (before tax)	Pension		OPEB	
	Actuarial losses (gains)	Past service gains	Actuarial losses (gains)	Past service gains
Balance, January 1, 2018	$ 25,128	$ (4,995)	$ (3,182)	$ (470)
Additions to AOCI	34,916	(1,875)	3,254	—
Amortization in current period	(1,074)	649	272	262
Loss on plan settlements	$ (2,547)	$ —	$ —	$ —
Reclassification to regulatory accounts (note 7(b))	(22,166)	—	(14,232)	—
Balance, December 31, 2018	**$ 34,257**	**$ (6,221)**	**$ (13,888)**	**$ (208)**
AOCI from business acquisition	**—**	**(285)**	**—**	**—**
Additions to AOCI	**17,905**	**(7,705)**	**14,871**	**—**
Amortization in current period	**(3,530)**	**784**	**409**	**208**
Reclassification to regulatory accounts (note 7(b))	**(10,122)**	**7,247**	**(10,538)**	**—**
Balance, December 31, 2019	**$ 38,510**	**$ (6,180)**	**$ (9,146)**	**$ —**

The movements in AOCI for Empire's and St. Lawrence Gas' pension and OPEB plans are reclassified to regulatory accounts since it is probable the unfunded amount of these plans will be afforded rate recovery (note 7(b)).

(in thousands of U.S. dollars, except as noted and per share amounts)

10. Pension and other post-employment benefits (continued)

(c) Assumptions

Weighted average assumptions used to determine net benefit obligation for 2019 and 2018 were as follows:

	Pension benefits		OPEB	
	2019	**2018**	**2019**	**2018**
Discount rate	**3.19%**	4.19%	**3.29%**	4.26%
Interest crediting rate (for cash balance plans)	**4.48%**	4.43%	**N/A**	N/A
Rate of compensation increase	**4.00%**	4.00%	**N/A**	N/A
Health care cost trend rate				
Before age 65			**6.125%**	6.25%
Age 65 and after			**6.125%**	6.25%
Assumed ultimate medical inflation rate			**4.75%**	4.75%
Year in which ultimate rate is reached			**2031**	2031

The mortality assumption for December 31, 2019 was updated to Pri-2012 mortality table and to the projected generationally scale MP-2019, adjusted to reflect the ultimate improvement rates in the 2019 Social Security Administration intermediate assumptions.

In selecting an assumed discount rate, the Company uses a modeling process that involves selecting a portfolio of high-quality corporate debt issuances (AA- or better) whose cash flows (via coupons or maturities) match the timing and amount of the Company's expected future benefit payments. The Company considers the results of this modeling process, as well as overall rates of return on high-quality corporate bonds and changes in such rates over time, to determine its assumed discount rate.

The rate of return assumptions are based on projected long-term market returns for the various asset classes in which the plans are invested, weighted by the target asset allocations.

Weighted average assumptions used to determine net benefit cost for 2019 and 2018 were as follows:

	Pension benefits		OPEB	
	2019	**2018**	**2019**	**2018**
Discount rate	**4.19%**	3.57%	**4.25%**	3.60%
Expected return on assets	**6.87%**	7.13%	**6.51%**	6.52%
Rate of compensation increase	**4.00%**	3.00%	**N/A**	N/A
Health care cost trend rate				
Before Age 65			**6.25%**	6.25%
Age 65 and after			**6.25%**	6.25%
Assumed ultimate medical inflation rate			**4.75%**	4.75%
Year in which ultimate rate is reached			**2031**	2024

(in thousands of U.S. dollars, except as noted and per share amounts)

10. Pension and other post-employment benefits (continued)

(d) Benefit costs

The following table lists the components of net benefit cost for the pension and OPEB plans. Service cost is recorded as part of operating expenses and non-service costs are recorded as part of other net losses in the consolidated statements of operations. The employee benefit costs related to businesses acquired are recorded in the consolidated statements of operations from the date of acquisition.

	Pension benefits		OPEB	
	2019	**2018**	**2019**	**2018**
Service cost	**$ 12,351**	$ 15,481	**$ 4,587**	$ 5,791
Non-service costs				
Interest cost	**20,222**	19,077	**7,575**	6,727
Expected return on plan assets	**(20,485)**	(27,820)	**(6,725)**	(7,451)
Amortization of net actuarial loss (gain)	**3,530**	1,074	**(409)**	(272)
Amortization of prior service credits	**(784)**	(649)	**(208)**	(262)
Amortization of regulatory assets/ liabilities	**12,082**	10,584	**2,534**	3,982
	$ 14,565	$ 2,266	**$ 2,767**	$ 2,724
Net benefit cost	**$ 26,916**	$ 17,747	**$ 7,354**	$ 8,515

(e) Plan assets

The Company's investment strategy for its pension and post-employment plan assets is to maintain a diversified portfolio of assets with the primary goal of meeting long-term cash requirements as they become due.

The Company's target asset allocation is as follows:

Asset class	Target (%)	Range (%)
Equity securities	68%	50% - 78%
Debt securities	32%	22% - 50%
	100%	

The fair values of investments as of December 31, 2019, by asset category, are as follows:

Asset class	Level 1	Percentage
Equity securities	**$ 414,985**	**73%**
Debt securities	**141,229**	**25%**
Other	**9,732**	**2%**
	$ 565,946	**100%**

As of December 31, 2019, the funds do not hold any material investments in APUC.

(f) Cash flows

The Company expects to contribute $24,140 to its pension plans and $5,736 to its post-employment benefit plans in 2020.

The expected benefit payments over the next ten years are as follows:

	2020	2021	2022	2023	2024	2025—2029
Pension plan	$ 34,461	$ 34,385	$ 35,383	$ 36,897	$ 37,848	$ 192,648
OPEB	7,469	7,867	8,379	8,903	9,361	52,864

(in thousands of U.S. dollars, except as noted and per share amounts)

11. Other assets

Other assets consist of the following:

	2019	2018
Restricted cash	**$ 24,787**	$ 18,954
OPEB plan assets (note 10(a))	**8,437**	3,161
Atlantica related prepaid amount (note 8(a))	**8,844**	—
Long-term deposits	**6,319**	1,207
Income taxes recoverable	**4,416**	1,961
Deferred financing costs	**5,477**	4,449
Other	**8,192**	4,967
	$ 66,472	$ 34,699
Less: current portion	**(7,764)**	(6,115)
	$ 58,708	$ 28,584

12. Other long-term liabilities

Other long-term liabilities consist of the following:

	2019	2018
Advances in aid of construction (a)	**$ 60,828**	$ 63,703
Environmental remediation obligation (b)	**58,061**	55,621
Asset retirement obligations (c)	**53,879**	43,291
Customer deposits (d)	**31,946**	29,974
Unamortized investment tax credits (e)	**18,234**	17,491
Deferred credits (f)	**18,952**	42,711
Preferred shares, Series C (g)	**13,793**	13,418
Lease liabilities (note 1(q))	**9,695**	3,436
Other (h)	**35,952**	28,360
	$ 301,340	$ 298,005
Less: current portion	**(57,939)**	(42,337)
	$ 243,401	$ 255,668

(a) Advances in aid of construction

The Company's regulated utilities have various agreements with real estate development companies (the "developers") conducting business within the Company's utility service territories, whereby funds are advanced to the Company by the developers to assist with funding some or all of the costs of the development.

In many instances, developer advances can be subject to refund, but the refund is non-interest bearing. Refunds of developer advances are made over periods generally ranging from 5 to 40 years. Advances not refunded within the prescribed period are usually not required to be repaid. After the prescribed period has lapsed, any remaining unpaid balance is transferred to contributions in aid of construction and recorded as an offsetting amount to the cost of property, plant and equipment. In 2019, $5,465 (2018 - $3,687) was transferred from advances in aid of construction to contributions in aid of construction.

(b) Environmental remediation obligation

A number of the Company's regulated utilities were named as potentially responsible parties for remediation of several sites at which hazardous waste is alleged to have been disposed as a result of historical operations of Manufactured Gas Plants ("MGP") and related facilities. The Company is currently investigating and remediating, as necessary, those MGP and related sites in accordance with plans submitted to the agency with authority for each of the respective sites.

(in thousands of U.S. dollars, except as noted and per share amounts)

12. Other long-term liabilities (continued)

(b) Environmental remediation obligation (continued)

The Company estimates the remaining undiscounted, unescalated cost of these MGP-related environmental cleanup activities will be $58,484 (2018 - $59,181), which at discount rates ranging from 1.7% to 2.1% represents the recorded accrual of $58,061 as of December 31, 2019 (2018 - $55,621). Approximately $36,382 is expected to be incurred over the next four years, with the balance of cash flows to be incurred over the following 31 years.

Changes in the environmental remediation obligation are as follows:

	2019	2018
Opening balance	**$ 55,621**	$ 54,322
Remediation activities	**(1,678)**	(2,163)
Accretion	**1,065**	1,479
Changes in cash flow estimates	**981**	4,051
Revision in assumptions	**2,072**	(2,068)
Closing balance	**$ 58,061**	$ 55,621

By rate orders, the Regulator provided for the recovery of actual expenditures for site investigation and remediation over a period of 7 years and accordingly, as of December 31, 2019, the Company has reflected a regulatory asset of $82,300 (2018 - $82,295) for the MGP and related sites (note 7(a)).

(c) Asset retirement obligations

Asset retirement obligations mainly relate to legal requirements to: (i) remove wind farm facilities upon termination of land leases; (ii) cut (disconnect from the distribution system), purge (cleanup of natural gas and Polychlorinated Biphenyls "PCB" contaminants) and cap gas mains within the gas distribution and transmission system when mains are retired in place, or sections of gas main are removed from the pipeline system; (iii) clean and remove storage tanks containing waste oil and other waste contaminants; (iv) remove certain river water intake structures and equipment; (v) dispose of coal combustion residuals and PCB contaminants and (vi) remove asbestos upon major renovation or demolition of structures and facilities.

Changes in the asset retirement obligations are as follows:

	2019	2018
Opening balance	**$ 43,291**	$ 44,166
Obligation assumed from business acquisition and constructed projects	**3,226**	225
Retirement activities	**(443)**	(5,130)
Accretion	**2,148**	1,974
Change in cash flow estimates	**5,657**	2,056
Closing balance	**$ 53,879**	$ 43,291

As the cost of retirement of utility assets, liability accretion and asset depreciation expense are expected to be recovered through rates, a corresponding regulatory asset is recorded (note 7(j)).

(d) Customer deposits

Customer deposits result from the Company’s obligation by state regulators to collect a deposit from customers of its facilities under certain circumstances when services are connected. The deposits are refundable as allowed under the facilities’ regulatory agreement.

(e) Unamortized investment tax credits

The unamortized investment tax credits were assumed in connection with the acquisition of Empire. The investment tax credits are associated with an investment made in a generating station. The credits are being amortized over the life of the generating station.

(in thousands of U.S. dollars, except as noted and per share amounts)

12. Other long-term liabilities (continued)

(f) Deferred credits

During the year, the Company settled $29,100 of contingent consideration related to the Company's investment in Atlantica (note 8(a)), and recorded an additional $5,000 contingent consideration related to the Company's investment in the San Antonio Water System (note 8(c)).

(g) Preferred shares, Series C

APUC has 100 redeemable Series C preferred shares issued and outstanding. Thirty-six of the Series C preferred shares are owned by related parties controlled by executives of the Company. The preferred shares are mandatorily redeemable in 2031 for C$53,400 per share and have a contractual cumulative cash dividend paid quarterly until the date of redemption based on a prescribed payment schedule indexed in proportion to the increase in CPI over the term of the shares. The Series C preferred shares are convertible into common shares at the option of the holder and the Company, at any time after May 20, 2031 and before June 19, 2031, at a conversion price of C$53,400 per share.

As these shares are mandatorily redeemable for cash, they are classified as liabilities in the consolidated financial statements. The Series C preferred shares are accounted for under the effective interest method, resulting in accretion of interest expense over the term of the shares. Dividend payments are recorded as a reduction of the Series C preferred share carrying value.

Estimated dividend payments due in the next five years and dividend and redemption payments thereafter are as follows:		
2020	$	1,035
2021		1,050
2022		1,070
2023		1,243
2024		1,454
Thereafter to 2031		9,439
Redemption amount		4,111
	$	19,402
Less: amounts representing interest		(5,609)
	$	13,793
Less current portion		(1,035)
	$	12,758

(h) Other

Convertible debentures

As at December 31, 2019, the carrying value of the convertible debentures was $342 (2018 - $470). The convertible debentures mature on March 31, 2026 and bear interest at an annual rate of 0% per C$1,000 principal amount of convertible debentures. The debentures are convertible at a price of C$10.60 per share into up to 44,130 common shares. During the year ended December 31, 2019, $148 (2018 - $447) of principal converted to 19,429 (2018 - 56,926) common shares of the Company (note 13).

(in thousands of U.S. dollars, except as noted and per share amounts)

13. Shareholders' capital

(a) Common shares

Number of common shares

	2019	2018
Common shares, beginning of year	**488,851,433**	431,765,935
Public offering (a)(i) and (a)(ii)	**28,009,341**	50,041,624
Dividend reinvestment plan (a)(iii)	**6,068,465**	5,880,843
Exercise of share-based awards (c)	**1,274,655**	1,106,105
Conversion of convertible debentures (note 12(h))	**19,429**	56,926
Common shares, end of year	**524,223,323**	488,851,433

Authorized

APUC is authorized to issue an unlimited number of common shares. The holders of the common shares are entitled to dividends if, as and when declared by the Board of Directors (the "Board"); to one vote per share at meetings of the holders of common shares; and upon liquidation, dissolution or winding up of APUC to receive pro rata the remaining property and assets of APUC, subject to the rights of any shares having priority over the common shares.

The Company has a shareholders' rights plan (the "Rights Plan"), which expires in 2022. Under the Rights Plan, one right is issued with each issued share of the Company. The rights remain attached to the shares and are not exercisable or separable unless one or more certain specified events occur. If a person or group acting in concert acquires 20 percent or more of the outstanding shares (subject to certain exceptions) of the Company, the rights will entitle the holders thereof (other than the acquiring person or group) to purchase shares at a 50 percent discount from the then-current market price. The rights provided under the Rights Plan are not triggered by any person making a "Permitted Bid", as defined in the Rights Plan.

(i) Public offering

In October 2019, APUC issued 26,252,542 common shares at $13.50 per share pursuant to a public offering for proceeds of $354,409 before issuance costs of $14,418.

On December 20, 2018, APUC issued 12,536,350 common shares at $10.09 (C$13.76) per share pursuant to a public offering for proceeds of $126,485 (C$172,500) before issuance costs of $366 (C$492).

On April 24, 2018, APUC issued 37,505,274 common shares at $9.23 (C$11.85) per share pursuant to a public offering for gross proceeds of $346,458 (C$444,437) before issuance costs of $590 (C$765).

(ii) At-the-market equity program

On February 28, 2019, APUC established an at-the-market equity program ("ATM program") that allows the Company to issue up to $250,000 of common shares from treasury to the public from time to time, at the Company's discretion, at the prevailing market price when issued on the TSX, the NYSE, or any other existing trading market for the common shares of the Company in Canada or the United States. During the year, the Company issued 1,756,799 common shares under the ATM program at an average price of $12.54 per common share for gross proceeds of $22,034 ($21,704 net of commissions). Other related costs, primarily related to the establishment of the ATM program, were $2,122.

(iii) Dividend reinvestment plan

The Company has a common shareholder dividend reinvestment plan, which provides an opportunity for shareholders to reinvest dividends for the purpose of purchasing common shares. Additional common shares acquired through the reinvestment of cash dividends are purchased in the open market or are issued by APUC at a discount of up to 5% from the average market price, all as determined by the Company from time to time. Subsequent to year-end, APUC issued an additional 1,244,696 common shares under the dividend reinvestment plan.

(in thousands of U.S. dollars, except as noted and per share amounts)

13. Shareholders' capital (continued)

(b) Preferred shares

APUC is authorized to issue an unlimited number of preferred shares, issuable in one or more series, containing terms and conditions as approved by the Board.

The Company has the following Series A and Series D preferred shares issued and outstanding as at December 31, 2019 and 2018:

Preferred shares	Number of shares		Price per share		Carrying amount C$		Carrying amount $
Series A	4,800,000	C$	25	C$	116,546	$	100,463
Series D	4,000,000	C$	25	C$	97,259	$	83,836
						$	184,299

The holders of Series A and Series D preferred shares had the right to convert their shares into cumulative floating rate preferred shares, Series B and Series E, respectively, subject to certain conditions, on December 31, 2018 and March 31, 2019, respectively, and every fifth year thereafter. Neither the Series A nor the Series B preferred shares were converted on December 31, 2018 and March 31, 2019 respectively.

The holders of Series A preferred shares are entitled to receive quarterly fixed cumulative preferential cash dividends, if, as and when declared by the Board. The dividend for each year up to, but excluding, December 31, 2018 was an annual amount of C$1.125 per share. The dividend rate for the five-year period from and including December 31, 2018 to but excluding December 31, 2023 will be $1.2905. The Series A dividend rate will reset on December 31, 2023 and every five years thereafter at a rate equal to the then five-year Government of Canada bond yield plus 2.94%. The Series A preferred shares are redeemable at C$25 per share at the option of the Company on December 31, 2023 and every fifth year thereafter.

The holders of Series D preferred shares are entitled to receive fixed cumulative preferential dividends as and when declared by the Board at an annual amount of C$1.25 per share for each year up to, but excluding, March 31, 2019. The dividend for the five-year period from and including March 31, 2019 to, but excluding, March 31, 2024 will be C$1.2728. The Series D dividend will reset on March 31, 2024 and every five years thereafter at a rate equal to the then five-year Government of Canada bond plus 3.28%. The Series D preferred shares are redeemable at C$25 per share at the option of the Company on March 31, 2024 and every fifth year thereafter.

The Company has 100 redeemable Series C preferred shares issued and outstanding. The mandatorily redeemable Series C preferred shares are recorded as a liability on the consolidated balance sheets as they are mandatorily redeemable for cash (note 12(g)).

(c) Share-based compensation

For the year ended December 31, 2019, APUC recorded $10,553 (2018 - $9,458) in total share-based compensation expense detailed as follows:

		2019		2018
Share options	**$**	**1,288**	$	2,054
Director deferred share units		**798**		714
Employee share purchase		**322**		312
Performance and restricted share units		**8,145**		6,378
Total share-based compensation	**$**	**10,553**	$	9,458

(in thousands of U.S. dollars, except as noted and per share amounts)

13. Shareholders' capital (continued)

(c) Share-based compensation (continued)

The compensation expense is recorded as part of administrative expenses in the consolidated statements of operations. The portion of share-based compensation costs capitalized as cost of construction is insignificant.

As of December 31, 2019, total unrecognized compensation costs related to non-vested options and PSUs were $1,252 and $12,750, respectively, and are expected to be recognized over a period of 1.68 and 1.86 years, respectively.

(i) Share option plan

The Company's share option plan (the "Plan") permits the grant of share options to officers, directors, employees and selected service providers. The aggregate number of shares that may be reserved for issuance under the Plan must not exceed 8% of the number of shares outstanding at the time the options are granted.

The number of shares subject to each option, the option price, the expiration date, the vesting and other terms and conditions relating to each option shall be determined by the Board (or the compensation committee of the Board ("Compensation Committee")) from time to time. Dividends on the underlying shares do not accumulate during the vesting period. Option holders may elect to surrender any portion of the vested options that is then exercisable in exchange for the "In-the-Money Amount". In accordance with the Plan, the "In-The-Money Amount" represents the excess, if any, of the market price of a share at such time over the option price, in each case such "In-the-Money Amount" being payable by the Company in cash or shares at the election of the Company. As the Company does not expect to settle these instruments in cash, these options are accounted for as equity awards.

The Compensation Committee may accelerate the vesting of the unvested options then held by the optionee at the Compensation Committee's discretion. In the event that the Company restates its financial results, any unpaid or unexercised options may be cancelled at the discretion of the Compensation Committee in accordance with the terms of the Company's clawback policy.

The estimated fair value of options, including the effect of estimated forfeitures, is recognized as expense on a straight-line basis over the options' vesting periods while ensuring that the cumulative amount of compensation cost recognized at least equals the value of the vested portion of the award at that date. The Company determines the fair value of options granted using the Black-Scholes option-pricing model. The risk-free interest rate is based on the zero-coupon Canada Government bond with a similar term to the expected life of the options at the grant date. Expected volatility was estimated based on the historical volatility of the Company's shares. The expected life was based on experience to date. The dividend yield rate was based upon recent historical dividends paid on APUC shares.

The following assumptions were used in determining the fair value of share options granted:

	2019	2018
Risk-free interest rate	**1.9%**	2.1%
Expected volatility	**20%**	21%
Expected dividend yield	**4.3%**	4.8%
Expected life	**5.50 years**	5.50 years
Weighted average grant date fair value per option	**C$ 1.66**	C$ 1.41

(in thousands of U.S. dollars, except as noted and per share amounts)

13. Shareholders' capital (continued)

(c) Share-based compensation (continued)

(i) Share option plan (continued)

Share option activity during the years is as follows:

	Number of awards		Weighted average exercise price	Weighted average remaining contractual term (years)		Aggregate intrinsic value
Balance, January 1, 2018	6,738,856	C$	11.18	6.32	C$	19,380
Granted	1,166,717		12.80	8.00		—
Exercised	(1,589,211)		10.66	5.02		5,059
Forfeited	(23,720)		12.80	—		—
Balance, December 31, 2018	**6,292,642**	**C$**	**11.61**	**5.75**	**C$**	**13,342**
Granted	**1,113,775**		**14.96**	**8.00**		**—**
Exercised	**(3,882,505)**		**11.23**	**4.45**		**6,225**
Forfeited	**—**		**—**	**—**		**—**
Balance, December 31, 2019	**3,523,912**	**C$**	**13.09**	**5.87**	**C$**	**18,609**
Exercisable, December 31, 2019	**1,735,241**	**C$**	**12.57**	**5.43**	**C$**	**14,559**

Subsequent to year-end, on February 19, 2020, 394,939 stock options were exercised at a weighted average price of C$12.77 in exchange for 115,517 common shares issued from treasury, and 279,422 options settled at their cash value as payment for the exercise price and tax withholdings related to the exercise of the options.

(ii) Employee share purchase plan

Under the Company's employee share purchase plan ("ESPP"), eligible employees may have a portion of their earnings withheld to be used to purchase the Company's common shares. The Company will match 20% of the employee contribution amount for the first five thousand dollars per employee contributed annually and 10% of the employee contribution amount for contributions over five thousand dollars up to ten thousand dollars annually. Common shares purchased through the Company match portion shall not be eligible for sale by the participant for a period of one year following the purchase date on which such shares were acquired. At the Company's option, the common shares may be (i) issued to participants from treasury at the average share price or (ii) acquired on behalf of participants by purchases through the facilities of the TSX or NYSE by an independent broker. The aggregate number of common shares reserved for issuance from treasury by APUC under the ESPP shall not exceed 2,000,000 common shares.

The Company uses the fair value based method to measure the compensation expense related to the Company's contribution. For the year ended December 31, 2019, a total of 253,538 common shares (2018 - 252,698) were issued to employees under the ESPP.

(iii) Director's deferred share units

Under the Company's deferred share unit plan, non-employee directors of the Company may elect annually to receive all or any portion of their compensation in DSUs in lieu of cash compensation. Directors' fees are paid on a quarterly basis and at the time of each payment of fees, the applicable amount is converted to DSUs. A DSU has a value equal to one of the Company's common shares. Dividends accumulate in the DSU account and are converted to DSUs based on the market value of the shares on that date. DSUs cannot be redeemed until the director retires, resigns, or otherwise leaves the Board. The DSUs provide for settlement in cash or shares at the election of the Company. As the Company does not expect to settle these instruments in cash, these options are accounted for as equity awards. As of December 31, 2019, 460,418 (2018 - 380,656) DSUs were outstanding pursuant to the election of the directors to defer a percentage of their director's fee in the form of DSUs. The aggregate number of common shares reserved for issuance from treasury by APUC under the DSU plan shall not exceed 1,000,000 common shares.

(in thousands of U.S. dollars, except as noted and per share amounts)

13. Shareholders' capital (continued)

(c) Share-based compensation (continued)

(iv) Performance and restricted share units

The Company offers a PSU and RSU plan to its employees as part of the Company's long-term incentive program. PSUs have been granted annually for three-year overlapping performance cycles. The PSUs vest at the end of the three-year cycle and will be calculated based on established performance criteria. At the end of the three-year performance periods, the number of common shares issued can range from 2.0% to 237% of the number of PSUs granted. RSU vesting conditions and dates vary by grant and are outlined in each award letter. RSUs are not subject to performance criteria. Dividends accumulating during the vesting period are converted to PSUs and RSUs based on the market value of the shares on that date and are recorded in equity as the dividends are declared. None of these PSUs or RSUs have voting rights. Any PSUs or RSUs not vested at the end of a performance period will expire. The PSUs and RSUs provide for settlement in cash or shares at the election of the Company. As the Company does not expect to settle these instruments in cash, these units are accounted for as equity awards. The aggregate number of common shares reserved for issuance from treasury by APUC under the PSU and RSU Plan shall not exceed 7,000,000 common shares.

Compensation expense associated with PSUs is recognized rateably over the performance period. Achievement of the performance criteria is estimated at the consolidated balance sheet dates. Compensation cost recognized is adjusted to reflect the performance conditions estimated to date.

A summary of the PSUs and RSUs follows:

	Number of awards		Weighted average grant-date fair value	Weighted average remaining contractual term (years)		Aggregate intrinsic value
Balance, January 1, 2018	955,028	C$	12.30	1.84	C$	13,428
Granted, including dividends	791,524		12.41	2.00		10,098
Exercised	(285,551)		10.02	—		3,691
Forfeited	(68,869)		13.02	—		—
Balance, December 31, 2018	**1,392,132**	**C$**	**12.75**	**1.60**	**C$**	**19,114**
Granted, including dividends	**1,471,442**		**14.69**	**2.00**		**16,302**
Exercised	**(344,340)**		**11.55**	**—**		**5,148**
Forfeited	**(107,191)**		**13.84**	**—**		**—**
Balance, December 31, 2019	**2,412,043**	**C$**	**14.00**	**1.86**	**C$**	**44,309**
Exercisable, December 31, 2019	**743,787**	**C$**	**13.21**	**—**	**C$**	**13,663**

(v) Bonus deferral RSUs

During 2018, the Company introduced a new bonus deferral RSU program to certain of its employees. Eligible employees have the option to receive a portion or all of their annual bonus payment in RSUs in lieu of cash. The RSUs provide for settlement in shares, and therefore these options are accounted for as equity awards. The RSUs granted are 100% vested and therefore, compensation expense associated with RSUs is recognized immediately upon issuance.

(in thousands of U.S. dollars, except as noted and per share amounts)

13. Shareholders' capital (continued)

(c) Share-based compensation (continued)

(vi) Bonus deferral RSUs

A summary of the bonus deferral RSUs follows:

	Number of awards	Weighted average grant-date fair value	Aggregate intrinsic value
Balance, December 31, 2017	—	C$ —	C$ —
Granted, including dividends	131,611	12.82	1,683
Exercised	(4,545)	12.82	61
Balance, December 31, 2018	**127,066**	**C$ 12.82**	**C$ 1,745**
Granted, including dividends	**135,324**	**15.40**	**2,084**
Balance and exercisable, December 31, 2019	**262,390**	**C$ 14.15**	**C$ 4,820**

14. Accumulated other comprehensive income (loss)

AOCI consists of the following balances, net of tax:

	Foreign currency cumulative translation	Unrealized gain on cash flow hedges	Pension and post-employment actuarial changes	Total
Balance, January 1, 2018	$ (47,701)	$ 55,366	$ (10,457)	$ (2,792)
Adoption of ASU 2018-02 on tax effects in AOCI	—	11,657	(1,032)	10,625
Other comprehensive income (loss)	(27,969)	1,567	2,046	(24,356)
Amounts reclassified from AOCI to the consolidated statement of operations	—	(4,257)	(86)	(4,343)
Net current period OCI	$ (27,969)	$ (2,690)	$ 1,960	$ (28,699)
OCI attributable to the non-controlling interests	1,481	—	—	1,481
Net current period OCI attributable to shareholders of APUC	$ (26,488)	$ (2,690)	$ 1,960	$ (27,218)
Balance, December 31, 2018	**$ (74,189)**	**$ 64,333**	**$ (9,529)**	**$ (19,385)**
Adoption of ASU 2017-12 on hedging (note 2(a))	**—**	**186**	**—**	**186**
Other comprehensive income (loss)	**7,795**	**19,177**	**(7,999)**	**18,973**
Amounts reclassified from AOCI to the consolidated statement of operations	**—**	**(8,597)**	**1,490**	**(7,107)**
Net current period OCI	**$ 7,795**	**$ 10,580**	**$ (6,509)**	**$ 11,866**
OCI attributable to the non-controlling interests	**(2,428)**	**—**	**—**	**(2,428)**
Net current period OCI attributable to shareholders of APUC	**$ 5,367**	**$ 10,580**	**$ (6,509)**	**$ 9,438**
Balance, December 31, 2019	**$ (68,822)**	**$ 75,099**	**$ (16,038)**	**$ (9,761)**

Amounts reclassified from AOCI for unrealized gain (loss) on cash flow hedges affected revenue from non-regulated energy sales while those for pension and post-employment actuarial changes affected pension and post-employment non-service costs.

(in thousands of U.S. dollars, except as noted and per share amounts)

15. Dividends

All dividends of the Company are made on a discretionary basis as determined by the Board. The Company declares and pays the dividends on its common shares in U.S. dollars. Dividends declared during the year were as follows:

	2019		2018	
	Dividend	**Dividend per share**	**Dividend**	**Dividend per share**
Common shares	**$ 277,835**	**$ 0.5512**	$ 235,440	$ 0.5011
Series A preferred shares	**C$ 6,194**	**C$ 1.2905**	C$ 5,400	C$ 1.1250
Series D preferred shares	**C$ 5,068**	**C$ 1.2671**	C$ 5,000	C$ 1.2500

16. Related party transactions

(a) Equity-method investments

The Company provides administrative and development services to its equity-method investees and is reimbursed for incurred costs. To that effect, during 2019, the Company charged its equity-method investees $12,374 (2018 - $11,390).

On December 30, 2019, the Company sold its interest in AWUSA to a joint venture entity in exchange for a note receivable of $30,293 (note 8(c)). No gain or loss was recognized on the sale. For the year, APUC recorded interest income of $6,007, and a fair value loss of $6,007 on its investment in the joint venture.

During the year, the Company sold the Sugar Creek Wind Project to AAGES Sugar Creek in exchange for a note receivable of $21,107, subject to certain adjustments. No gain was recorded on deconsolidation of the Sugar Creek net assets. However, an amount of $15,765, or $11,412, net of tax, was reclassified from AOCI into earnings as a result of the discontinuation of hedge accounting on energy derivatives put in place early in the development of Sugar Creek (note 24(b)(ii)).

During the year, the Company entered into an enhanced cooperation agreement with Atlantica to, among other things, provide a framework for evaluating mutually advantageous transactions. For a period of one year from the date of the agreement, Atlantica has an exclusive right of first offer for interests in certain Renewable Energy assets.

(b) Redeemable non-controlling interest held by related party

Redeemable non-controlling interest held by related party represents a preference share in a consolidated subsidiary of the Company acquired by AAGES B.V. in 2018 for $305,000 (note 8(a)). Redemption is not considered probable as at December 31, 2019. The Company incurred non-controlling interest attributable to AAGES B.V. of $16,482 (2018 - $2,622) and recorded distributions of $18,241 (2018 - $nil) during the year (note 17).

(c) Non-controlling interest held by related party

Non-controlling interest held by related party represents interest in a consolidated subsidiary of the Company acquired by AYES Canada in May 2019 for $96,752 (note 8(b)). The Company recorded distributions of $26,465 during the year.

(d) Long Sault Hydro Facility

Effective December 31, 2013, APUC acquired the shares of Algonquin Power Corporation Inc. (“APC”), which was partially owned by Senior Executives. APC owns the partnership interest in the 18 MW Long Sault Hydro Facility. A final post-closing adjustment related to the transaction remains outstanding.

The above related party transactions have been recorded at the exchange amounts agreed to by the parties to the transactions.

(in thousands of U.S. dollars, except as noted and per share amounts)

17. Non-controlling interests and redeemable non-controlling interests

Net effect attributable to non-controlling interests for the years ended December 31 consists of the following:

	2019	2018
HLBV and other adjustments attributable to:		
Non-controlling interests - tax equity partnership units	$ **(55,963)**	$ (103,150)
Non-controlling interests - redeemable tax equity partnership units	**(9,006)**	(7,545)
Other net earnings attributable to:		
Non-controlling interests	**2,553**	2,174
	$ **(62,416)**	$ (108,521)
Redeemable non-controlling interest, held by related party	**16,482**	2,622
Net effect of non-controlling interests	$ **(45,934)**	$ (105,899)

The non-controlling tax equity investors ("tax equity partnership units") in the Company's U.S. wind power and solar power generating facilities are entitled to allocations of earnings, tax attributes and cash flows in accordance with contractual agreements. The share of earnings attributable to the non-controlling interest holders in these subsidiaries is calculated using the HLBV method of accounting as described in note 1(s).

The terms of the arrangement refer to the tax rate in effect when the benefits are delivered. As such, the U.S. federal corporate tax rate of 35% was used to calculate HLBV as at December 31, 2017. The reduced U.S. federal corporate tax rate of 21% and other certain measures included in the Tax Act effective January 1, 2018 were reflected in the calculation of HLBV in 2018. The changes accelerated HLBV income from future years to the first quarter of 2018 in the amount of $55,900.

Non-controlling interests

As of December 31, 2019, non-controlling interests of $457,834 (2018 - $519,896) include partnership units held by tax equity investors in certain U.S. wind power and solar generating facilities of $457,000 (2018 - 519,100) and other non-controlling interests of $834 (2018 - $796). Contributions from tax equity investors of $15,250 were received for the Great Bay Solar I Facility in 2018 (note 3(g)).

Non-controlling interest held by related party

Non-controlling interest was issued to AYES Canada in May 2019 for $96,752 (note 8(b)). The balance as of December 31, 2019 was $73,707.

Redeemable non-controlling interests

Non-controlling interests in subsidiaries that are redeemable upon the occurrence of uncertain events not solely within APUC's control are classified as temporary equity on the consolidated balance sheets. If the redemption is probable or currently redeemable, the Company records the instruments at their redemption value. Redemption is not considered probable as of December 31, 2019. Changes in redeemable non-controlling interests are as follows:

	Redeemable non-controlling interests held by related party		Redeemable non-controlling interests	
	2019	2018	2019	2018
Opening balance	$ **307,622**	$ —	$ **33,364**	$ 41,553
Net effect from operations	**16,482**	2,622	**(9,006)**	(7,545)
Contributions, net of costs	**—**	305,000	**3,403**	—
Dividends and distributions declared	**(18,241)**	—	**(1,848)**	(644)
Closing balance	$ **305,863**	$ 307,622	$ **25,913**	$ 33,364

During 2019, contributions from tax equity partnership investors of $3,403 were received for the Turquoise Solar Facility (note 3(b)). During 2018, contributions of $305,000 were received from AAGES B.V. for a preference share of AY Holdings (note 8(a)).

(in thousands of U.S. dollars, except as noted and per share amounts)

18. Income taxes

The provision for income taxes in the consolidated statements of operations represents an effective tax rate different than the Canadian enacted statutory rate of 26.5% (2018 - 26.5%). The differences are as follows:

	2019	2018
Expected income tax expense at Canadian statutory rate	**$ 147,093**	$ 35,102
Increase (decrease) resulting from:		
Effect of differences in tax rates on transactions in and within foreign jurisdictions and change in tax rates	**(27,703)**	(28,064)
Adjustments from investments carried at fair value	**(60,730)**	25,870
Non-controlling interests share of income	**16,991**	29,637
Non-deductible acquisition costs	**2,500**	4,267
Tax credits	**(9,332)**	(1,419)
Adjustment relating to prior periods	**(1,240)**	3,673
U.S. Tax reform and related deferred tax adjustments (1)	**—**	(18,363)
Other	**2,538**	2,669
Income tax expense	**$ 70,117**	$ 53,372

(1) In 2017, the Tax Cuts and Jobs Act ("Tax Act") implemented significant changes to U.S. tax legislation, including a reduction in the U.S. federal corporate income tax from 35% to 21%, effective January 1, 2018. The Company's U.S. entities were required to remeasure their deferred tax assets and liabilities at the new corporate income tax rate as at the date of enactment. In 2018, an adjustment related to the implementation of U.S. Tax Reform resulted in a non-cash accounting benefit of $18,363, which was recorded in the Company's 2018 consolidated statement of operations.

For the years ended December 31, 2019 and 2018, earnings before income taxes consist of the following:

	2019	2018
Canada	**$ 351,908**	$ (109,537)
U.S.	**203,159**	241,998
	$ 555,067	$ 132,461

Income tax expense (recovery) attributable to income (loss) consists of:

	Current	Deferred	Total
Year ended December 31, 2019			
Canada	**$ 6,695**	**$ 17,607**	**$ 24,302**
United States	**9,736**	**36,079**	**45,815**
	$ 16,431	**$ 53,686**	**$ 70,117**
Year ended December 31, 2018			
Canada	$ 2,872	$ (14,197)	$ (11,325)
United States	8,475	56,222	64,697
	$ 11,347	$ 42,025	$ 53,372

(in thousands of U.S. dollars, except as noted and per share amounts)

18. Income taxes (continued)

The tax effect of temporary differences between the financial statement carrying amounts of assets and liabilities and their respective tax bases that give rise to significant portions of the deferred tax assets and deferred tax liabilities as of December 31, 2019 and 2018 are presented below:

	2019	2018
Deferred tax assets:		
Non-capital loss, investment tax credits, currently non-deductible interest expenses, and financing costs	**$ 382,448**	$ 329,099
Pension and OPEB	**54,113**	48,586
Environmental obligation	**15,541**	14,790
Regulatory liabilities	**160,200**	161,560
Other	**59,103**	45,193
Total deferred income tax assets	**$ 671,405**	$ 599,228
Less: valuation allowance	**(29,447)**	(28,018)
Total deferred tax assets	**$ 641,958**	$ 571,210
Deferred tax liabilities:		
Property, plant and equipment	**$ 707,185**	$ 653,962
Outside basis in partnership	**235,063**	167,659
Regulatory accounts	**145,852**	113,758
Other	**14,811**	7,561
Total deferred tax liabilities	**$ 1,102,911**	$ 942,940
Net deferred tax liabilities	**$ (460,953)**	$ (371,730)
Consolidated balance sheets classification:		
Deferred tax assets	**$ 30,585**	$ 72,415
Deferred tax liabilities	**(491,538)**	(444,145)
Net deferred tax liabilities	**$ (460,953)**	$ (371,730)

The valuation allowance for deferred tax assets as at December 31, 2019 was $29,447 (2018 - $28,018). The valuation allowance primarily relates to operating losses that, in the judgment of management, are not more likely than not to be realized. In assessing the realizability of deferred tax assets, management considers whether it is more likely than not that some portion or all of the deferred tax assets will not be realized. The ultimate realization of deferred tax assets is dependent upon the generation of future taxable income during the periods in which those temporary differences become deductible. Management considers the scheduled reversal of deferred tax liabilities (including the impact of available carryback and carryforward periods), projected future taxable income, and tax-planning strategies in making this assessment.

As of December 31, 2019, the Company had non-capital losses carried forward available to reduce future years' taxable income, which expire as follows:

Year of expiry	Non-capital loss carryforwards
2020 and onwards	$ 1,091,322

The Company has provided for deferred income taxes for the estimated tax cost of distributed earnings of certain of its subsidiaries. Deferred income taxes have not been provided on approximately $370,682 of undistributed earnings of certain foreign subsidiaries, as the Company has concluded that such earnings are indefinitely reinvested and should not give rise to additional tax liabilities. A determination of the amount of the unrecognized tax liability relating to the remittance of such undistributed earnings is not practicable.

(in thousands of U.S. dollars, except as noted and per share amounts)

19. Other losses

Other losses consist of the following:

	2019	2018
Pension and other post-employment non-service costs (note 10)	**$ (17,332)**	$ (4,990)
Acquisition and transition-related costs (note 3)	**(11,609)**	(687)
Other	**(15,085)**	(2,725)
	$ (44,026)	$ (8,402)

20. Basic and diluted net earnings per share

Basic and diluted earnings per share have been calculated on the basis of net earnings attributable to the common shareholders of the Company and the weighted average number of common shares and bonus deferral restricted share units outstanding. Diluted net earnings per share is computed using the weighted-average number of common shares, subscription receipts outstanding, additional shares issued subsequent to year-end under the dividend reinvestment plan, PSUs, RSUs and DSUs outstanding during the year and, if dilutive, potential incremental common shares resulting from the application of the treasury stock method to outstanding share options and additional shares issued subsequent to quarter-end under the dividend reinvestment plan. The convertible debentures (note 12(h)) are convertible into common shares at any time prior to maturity or redemption by the Company. The shares issuable upon conversion of the convertible debentures are included in diluted earnings per share.

The reconciliation of the net earnings and the weighted average shares used in the computation of basic and diluted earnings per share are as follows:

	2019	2018
Net earnings attributable to shareholders of APUC	**$ 530,884**	$ 184,988
Series A preferred shares dividend	**4,666**	4,169
Series D preferred shares dividend	**3,820**	3,858
Net earnings attributable to common shareholders of APUC from continuing operations – basic and diluted	**$ 522,398**	$ 176,961
Weighted average number of shares		
Basic	**499,910,876**	461,818,023
Effect of dilutive securities	**4,828,678**	4,227,595
Diluted	**504,739,554**	466,045,618

The shares potentially issuable as a result of 1,113,775 share options (2018 - 3,380,184) are excluded from this calculation as they are anti-dilutive.

(in thousands of U.S. dollars, except as noted and per share amounts)

21. Segmented information

The Company is managed under two primary business units consisting of the Regulated Services Group and the Renewable Energy Group. The two business units are the two segments of the Company.

The Regulated Services Group, the Company's regulated operating unit, owns and operates a portfolio of electric, natural gas, water distribution and wastewater collection utility systems and transmission operations in the United States and Canada; the Renewable Energy Group, the Company's non-regulated operating unit, owns and operates a diversified portfolio of renewable and thermal electric generation assets in North America and internationally.

For purposes of evaluating the performance of the business units, the Company allocates the realized portion of any gains or losses on financial instruments to the specific business units. Dividend income from Atlantica and AYES Canada are included in the operations of the Renewable Energy Group while interest income from San Antonio Water System is included in the operations of the Regulated Services Group. Equity method gains and losses are included in the operations of the Regulated Services Group or Renewable Energy Group based on the nature of the activities of the investees. The change in value of investments carried at fair value and unrealized portion of any gains or losses on derivative instruments not designated in a hedging relationship are not considered in management's evaluation of divisional performance and are therefore allocated and reported under corporate.

	Year ended December 31, 2019			
	Regulated Services Group	Renewable Energy Group	Corporate	Total
Revenue [(1)(2)]	$ 1,366,971	$ 257,950	$ —	$ 1,624,921
Fuel, power and water purchased	426,046	17,258	—	443,304
Net revenue	940,925	240,692	—	1,181,617
Operating expenses	396,559	75,209	221	471,989
Administrative expenses	36,628	19,405	769	56,802
Depreciation and amortization	194,498	88,825	981	284,304
Loss on foreign exchange	—	—	3,146	3,146
Operating income (loss)	313,240	57,253	(5,117)	365,376
Interest expense	(101,518)	(61,039)	(18,931)	(181,488)
Income from long-term investments	9,334	104,025	285,733	399,092
Other income (expenses)	(32,292)	15,946	(11,567)	(27,913)
Earnings before income taxes	$ 188,764	$ 116,185	$ 250,118	$ 555,067
Property, plant and equipment	$ 4,754,373	$ 2,444,382	$ 32,909	$ 7,231,664
Investments carried at fair value	27,072	1,267,075	—	1,294,147
Equity-method investees	29,827	53,670	273	83,770
Total assets	6,816,063	4,014,067	81,340	10,911,470
Capital expenditures	$ 478,936	$ 102,396	$ —	$ 581,332

(1) Revenue includes $22,282 related to net hedging gains from energy derivative contracts for the year ended December 31, 2019 that do not represent revenue recognized from contracts with customers.

(2) Regulated Services Group revenue includes $(4,405) related to alternative revenue programs for the year ended December 31, 2019 that do not represent revenue recognized from contracts with customers.

(in thousands of U.S. dollars, except as noted and per share amounts)

21. Segmented information (continued)

	Year ended December 31, 2018			
	Regulated Services Group	Renewable Energy Group	Corporate	Total
Revenue [1][2]	$ 1,401,240	$ 247,223	$ —	$ 1,648,463
Fuel and power purchased	456,974	27,164	—	484,138
Net revenue	944,266	220,059	—	1,164,325
Operating expenses	401,486	70,980	—	472,466
Administrative expenses	33,234	18,539	937	52,710
Depreciation and amortization	177,719	82,044	1,009	260,772
Gain on foreign exchange	—	—	(58)	(58)
Operating income (loss)	331,827	48,496	(1,888)	378,435
Interest expense	(99,063)	(50,920)	(2,135)	(152,118)
Income (loss) from long-term investments	5,558	45,741	(136,117)	(84,818)
Other expenses	(6,775)	(1,576)	(687)	(9,038)
Earnings (loss) before income taxes	$ 231,547	$ 41,741	$ (140,827)	$ 132,461
Property, plant and equipment	$ 4,210,115	$ 2,152,420	$ 31,023	$ 6,393,558
Investment carried at fair value	—	814,530	—	814,530
Equity-method investees	55	29,273	260	29,588
Total assets	6,022,262	3,269,786	106,541	9,398,589
Capital expenditures	$ 370,221	$ 96,148	$ —	$ 466,369

(1) Revenue includes $14,953 related to net hedging gains from energy derivative contracts for the year ended December 31, 2018 that do not represent revenue recognized from contracts with customers.

(2) Regulated Services Group revenue includes $7,425 related to alternative revenue programs for the year ended December 31, 2018 that do not represent revenue recognized from contracts with customers.

The majority of non-regulated energy sales are earned from contracts with large public utilities. The Company has mitigated its credit risk to the extent possible by selling energy to large utilities in various North American locations. None of the utilities contribute more than 10% of total revenue.

(in thousands of U.S. dollars, except as noted and per share amounts)

21. Segmented information (continued)

APUC operates in the independent power and utility industries in both Canada and the United States. Information on operations by geographic area is as follows:

	2019	2018
Revenue		
Canada	**$ 87,226**	$ 70,358
United States	**1,537,695**	1,578,105
	$ 1,624,921	$ 1,648,463
Property, plant and equipment		
Canada	**$ 752,016**	$ 415,979
United States	**6,479,648**	5,977,579
	$ 7,231,664	$ 6,393,558
Intangible assets		
Canada	**$ 23,795**	$ 23,994
United States	**23,821**	31,000
	$ 47,616	$ 54,994

Revenue is attributed to the two countries based on the location of the underlying generating and utility facilities.

22. Commitments and contingencies

(a) Contingencies

APUC and its subsidiaries are involved in various claims and litigation arising out of the ordinary course and conduct of its business. Although such matters cannot be predicted with certainty, management does not consider APUC's exposure to such litigation to be material to these consolidated financial statements. Accruals for any contingencies related to these items are recorded in the consolidated financial statements at the time it is concluded that its occurrence is probable and the related liability is estimable.

Claim by Gaia Power Inc.

On October 30, 2018, Gaia Power Inc. ("Gaia") commenced an action in the Ontario Superior Court of Justice against APUC and certain of its subsidiaries, claiming damages of not less than $345,000 and punitive damages in the sum of $25,000. The action arises from Gaia's 2010 sale, to a subsidiary of APUC, of Gaia's interest in certain proposed wind farm projects in Canada. Pursuant to a 2010 royalty agreement, Gaia is entitled to royalty payments if the projects are developed and achieve certain agreed targets. It is too early to determine the likelihood of success in this lawsuit; however, APUC intends to vigorously defend it.

Condemnation expropriation proceedings

Liberty Utilities (Apple Valley Ranchos Water) Corp. is the subject of a condemnation lawsuit filed by the town of Apple Valley. A court will determine the necessity of the taking by Apple Valley and, if established, a jury will determine the fair market value of the assets being condemned. Resolution of the condemnation proceedings is expected to take two to three years. Any taking by government entities would legally require fair compensation to be paid; however, there is no assurance that the value received as a result of the condemnation will be sufficient to recover the Company's net book value of the utility assets taken.

(in thousands of U.S. dollars, except as noted and per share amounts)

22. Commitments and contingencies (continued)

(b) Commitments

In addition to the commitments related to the proposed acquisitions and development projects disclosed in notes 3 and 8, the following significant commitments exist as of December 31, 2019.

APUC has outstanding purchase commitments for power purchases, gas supply and service agreements, service agreements, capital project commitments and land easements.

Detailed below are estimates of future commitments under these arrangements:

	Year 1	Year 2	Year 3	Year 4	Year 5	Thereafter	Total
Power purchase (i)	$ 30,672	$ 11,422	$ 11,338	$ 11,566	$ 11,796	$ 179,412	$ 256,206
Gas supply and service agreements (ii)	83,083	60,699	49,217	46,406	41,538	135,926	416,869
Service agreements	47,950	40,456	41,554	45,611	47,005	293,436	516,012
Capital projects	104,809	114,806	—	—	—	—	219,615
Land easements	6,603	6,673	6,744	6,835	6,918	200,891	234,664
Total	$273,117	$234,056	$108,853	$110,418	$107,257	$ 809,665	$ 1,643,366

(i) Power purchase: APUC's electric distribution facilities have commitments to purchase physical quantities of power for load serving requirements. The commitment amounts included in the table above are based on market prices as of December 31, 2019. However, the effects of purchased power unit cost adjustments are mitigated through a purchased power rate-adjustment mechanism.

(ii) Gas supply and service agreements: APUC's gas distribution facilities and thermal generation facilities have commitments to purchase physical quantities of natural gas under contracts for purposes of load serving requirements and of generating power.

23. Non-cash operating items

The changes in non-cash operating items consist of the following:

	2019	2018
Accounts receivable	**$ (20,857)**	$ 3,005
Fuel and natural gas in storage	**13,985**	1,351
Supplies and consumables inventory	**(6,028)**	(7,189)
Income taxes recoverable	**17,796**	(763)
Prepaid expenses	**(7,501)**	2,907
Accounts payable	**63,854**	(22,915)
Accrued liabilities	**8,872**	28,687
Current income tax liability	**(5,016)**	2,974
Asset retirements and environmental obligations	**(2,494)**	(7,293)
Net regulatory assets and liabilities	**(2,308)**	(8,890)
	$ 60,303	$ (8,126)

(in thousands of U.S. dollars, except as noted and per share amounts)

24. Financial instruments

(a) Fair value of financial instruments

2019	Carrying amount	Fair value	Level 1	Level 2	Level 3
Long-term investments carried at fair value	$ 1,294,147	$ 1,294,147	1,178,581	$ 27,072	$ 88,494
Development loans and other receivables	37,050	37,984	—	37,984	—
Derivative instruments:					
Energy contracts designated as a cash flow hedge	65,304	65,304	—	—	65,304
Energy contracts not designated as a hedge	20,384	20,384	—	—	20,384
Commodity contracts for regulated operations	16	16	—	16	—
Total derivative instruments	85,704	85,704	—	16	85,688
Total financial assets	$ 1,416,901	$ 1,417,835	$ 1,178,581	$ 65,072	$ 174,182
Long-term debt	$ 3,931,868	$ 4,284,068	$ 1,495,153	$ 2,788,915	$ —
Convertible debentures	342	623	623	—	—
Preferred shares, Series C	13,793	15,120	—	15,120	—
Derivative instruments:					
Energy contracts designated as a cash flow hedge	789	789	—	—	789
Energy contracts not designated as a hedge	38	38	—	—	38
Cross-currency swap designated as a net investment hedge	81,765	81,765	—	81,765	—
Commodity contracts for regulated operations	2,072	2,072	—	2,072	—
Total derivative instruments	84,664	84,664	—	83,837	827
Total financial liabilities	$ 4,030,667	$ 4,384,475	$ 1,495,776	$ 2,887,872	$ 827

(in thousands of U.S. dollars, except as noted and per share amounts)

24. Financial instruments (continued)

(a) Fair value of financial instruments (continued)

2018	Carrying amount	Fair value	Level 1	Level 2	Level 3
Long-term investment carried at fair value	$ 814,530	$ 814,530	$ 814,530	$ —	$ —
Development loans and other receivables	103,696	110,019	—	110,019	—
Derivative instruments [1]:					
Energy contracts designated as a cash flow hedge	61,838	61,838	—	—	61,838
Currency forward contract not designated as a hedge	869	869	—	869	—
Commodity contracts for regulatory operations	101	101	—	101	—
Total derivative instruments	62,808	62,808	—	970	61,838
Total financial assets	$ 981,034	$ 987,357	$ 814,530	$ 110,989	$ 61,838
Long-term debt	$ 3,336,795	$ 3,356,773	$ 768,400	$2,588,373	$ —
Convertible debentures	470	639	639	—	—
Preferred shares, Series C	13,418	13,703	—	13,703	—
Derivative instruments:					
Energy contracts designated as a cash flow hedge	57	57	—	—	57
Cross-currency swap designated as a net investment hedge	93,198	93,198	—	93,198	—
Interest rate swaps designated as a hedge	8,473	8,473	—	8,473	—
Commodity contracts for regulated operations	1,114	1,114	—	1,114	—
Total derivative instruments	102,842	102,842	—	102,785	57
Total financial liabilities	$ 3,453,525	$ 3,473,957	$ 769,039	$2,704,861	$ 57

[1] Balance of $441 associated with certain weather derivatives have been excluded, as they are accounted for based on intrinsic value rather than fair value.

The Company has determined that the carrying value of its short-term financial assets and liabilities approximates fair value as of December 31, 2019 and 2018 due to the short-term maturity of these instruments.

The fair value of development loans and other receivables (level 2) is determined using a discounted cash flow method, using estimated current market rates for similar instruments adjusted for estimated credit risk as determined by management.

The fair value of the investment in Atlantica (level 1) is measured at the closing price on the NASDAQ stock exchange adjusted for the impact of the expected settlement under the purchase agreement pursuant to the prepayment of $53,750 (note 8(a)).

(in thousands of U.S. dollars, except as noted and per share amounts)

24. Financial instruments (continued)

(a) Fair value of financial instruments (continued)

The Company's level 1 fair value of long-term debt is measured at the closing price on the NYSE and the Canadian over-the-counter closing price. The Company's level 2 fair value of long-term debt at fixed interest rates and Series C preferred shares has been determined using a discounted cash flow method and current interest rates. The Company's level 2 fair value of convertible debentures has been determined as the greater of their face value and the quoted value of APUC's common shares on a converted basis.

The Company's level 2 fair value derivative instruments primarily consist of swaps, options, rights and forward physical derivatives where market data for pricing inputs are observable. Level 2 pricing inputs are obtained from various market indices and utilize discounting based on quoted interest rate curves which are observable in the marketplace.

The Company's level 3 instruments consist of energy contracts for electricity sales and the fair value of the Company's investment in AYES Canada. The significant unobservable inputs used in the fair value measurement of energy contracts are the internally developed forward market prices ranging from $13.33 to $178.65 with a weighted average of $23.66 as of December 31, 2019. The weighted average forward market prices are developed based on the quantity of energy expected to be sold monthly and the expected forward price during that month. The change in the fair value of the energy contracts is detailed in notes 24(b)(ii) and 24(b)(iv). The significant unobservable inputs used in the fair value measurement of the Company's AYES Canada investment are the expected cash flows, the discount rates applied to these cash flows ranging from 8.75% to 9.50% with a weighted average of 9.42%, and the expected volatility of Atlantica's share price ranging from 18% to 22% as of December 31, 2019. Significant increases (decreases) in expected cash flows or increases (decreases) in discount rate in isolation would have resulted in a significantly lower (higher) fair value measurement.

(b) Derivative instruments

Derivative instruments are recognized on the consolidated balance sheets as either assets or liabilities and measured at fair value at each reporting period.

(i) Commodity derivatives – regulated accounting

The Company uses derivative financial instruments to reduce the cash flow variability associated with the purchase price for a portion of future natural gas purchases associated with its regulated gas and electric service territories. The Company's strategy is to minimize fluctuations in gas sale prices to regulated customers.

The following are commodity volumes, in dekatherms ("dths") associated with the above derivative contracts:

		2019
Financial contracts:	Swaps	**2,134,739**
	Options	**150,000**
	Forward contracts	**2,500,000**
		4,784,739

The accounting for these derivative instruments is subject to guidance for rate regulated enterprises. Therefore, the fair value of these derivatives is recorded as current or long-term assets and liabilities, with offsetting positions recorded as regulatory assets and regulatory liabilities in the consolidated balance sheets. Most of the gains or losses on the settlement of these contracts are included in the calculation of the fuel and commodity costs adjustments (note 7(e)). As a result, the changes in fair value of these natural gas derivative contracts and their offsetting adjustment to regulatory assets and liabilities had no earnings impact.

(in thousands of U.S. dollars, except as noted and per share amounts)

24. Financial instruments (continued)

(b) Derivative instruments (continued)

(i) Commodity derivatives – regulated accounting (continued)

The following table presents the impact of the change in the fair value of the Company's natural gas derivative contracts had on the consolidated balance sheets:

		2019		2018
Regulatory assets:				
Swap contracts	**$**	**28**	$	66
Option contracts		**38**		—
Forward contracts	**$**	**1,830**	$	—
Regulatory liabilities:				
Swap contracts	**$**	**743**	$	218
Option contracts		**—**		134
Forward contracts	**$**	**—**	$	1,259

(ii) Cash flow hedges

The Company reduces the price risk on the expected future sale of power generation at Sandy Ridge, Senate and Minonk Wind Facilities by entering into the following long-term energy derivative contracts.

Notional quantity (MW-hrs)	Expiry	Receive average prices (per MW-hr)	Pay floating price (per MW-hr)
757,075	December 2028	35.35	PJM Western HUB
3,443,530	December 2027	25.54	PJM NI HUB
2,665,068	December 2027	36.46	ERCOT North HUB

In January 2019, the Company entered into a long-term energy derivative contract to reduce the price risk on the expected future sale of power generation at Sugar Creek. On September 30, 2019, the Company sold the derivative contract together with 100% of its ownership interest in Sugar Creek to AAGES Sugar Creek. The novation and transfer of the derivative contract was subject to counterparty approval, which was received subsequent to year-end in Q1 2020. As a result, the hedge relationship for the Sugar Creek energy derivative was discontinued. Amounts in AOCI of $15,765 and related tax were reclassified from AOCI into earnings in 2019 (note 24(b)(iv)).

During the year, the Company entered into an energy derivative contract to reduce the price risk on the expected future purchase of power on the open market at its Tinker Hydroelectric Facility with a notional quantity of 151,680 MW-hours and a price of $38.95 per MW-hr. The contract expires February 2022.

The Company was party to a 10-year forward-starting interest rate swap beginning on July 25, 2018 in order to reduce the interest rate risk related to the probable issuance on that date of a 10-year C$135,000 bond. During 2018, the Company amended and extended the forward-starting date of the interest rate swap to begin on March 29, 2019. During the year, the Company settled the forward-starting interest rate swap contract as it issued C$300,000 10-year senior unsecured notes with an interest rate of 4.60% (note 9(d)).

On May 23, 2019, the Company entered into a cross-currency swap, coterminous with the subordinated unsecured notes (note 9(e)), to effectively convert the $350,000 U.S. dollar denominated offering into Canadian dollars. The change in the carrying amount of the notes due to changes in spot exchange rates is recognized each period in the consolidated statements of operations as loss (gain) on foreign exchange. The Company designated the entire notional amount of the cross-currency fixed-for-fixed interest rate swap as a hedge of the foreign currency exposure related to cash flows for the interest and principal repayments on the notes. The gain or loss related to the fair value changes of the swap is first reported in OCI and a portion of the change is then reclassified from AOCI into earnings at each reporting date to offset the foreign exchange transaction gain or loss on the notes.

(in thousands of U.S. dollars, except as noted and per share amounts)

24. Financial instruments (continued)

(b) Derivative instruments (continued)

(ii) Cash flow hedges (continued)

In September 2019, the Company entered into a forward-starting interest rate swap in order to reduce the interest rate risk related to the quarterly interest payments between July 1, 2024 and July 1, 2029 on the subordinated unsecured notes (note 9(e)). The Company designated the entire notional amount of the three pay-variable and receive-fixed interest rate swaps as a hedge of the future quarterly variable-rate interest payments associated with the subordinated unsecured notes.

The following table summarizes OCI attributable to derivative financial instruments designated as a cash flow hedge:

		2019		2018
Effective portion of cash flow hedge	**$**	**19,177**	$	1,567
Amortization of cash flow hedge		**(33)**		(33)
Amounts reclassified from AOCI		**(8,564)**		(4,224)
OCI attributable to shareholders of APUC	**$**	**10,580**	$	(2,690)

The Company expects $8,704 and $2,203 of unrealized gains currently in AOCI to be reclassified, net of taxes into non-regulated energy sales and interest expense, respectively, within the next twelve months, as the underlying hedged transactions settle.

(iii) Foreign exchange hedge of net investment in foreign operation

The Company is exposed to currency fluctuations from its Canadian-based operations. APUC manages this risk primarily through the use of natural hedges by using Canadian long-term debt to finance its Canadian operations and a combination of foreign exchange forward contracts and spot purchases. APUC only enters into foreign exchange forward contracts with major North American financial institutions having a credit rating of A or better, thus reducing credit risk on these forward contracts.

The Company's Canadian operations are determined to have the Canadian dollar as their functional currency and are exposed to currency fluctuations from their U.S. dollar transactions. The Company designates the amounts drawn on its revolving and bank credit facilities denominated in U.S. dollars as a hedge of the foreign currency exposure of its net investment in its U.S. investments and subsidiaries. The related foreign currency transaction gain or loss designated as, and effective as, a hedge of the net investment in a foreign operation are reported in the same manner as the translation adjustment (in OCI) related to the net investment. A foreign currency gain of $35,277 for the year ended December 31, 2019 (2018 - loss of $28,705) was recorded in OCI.

Concurrent with its C$150,000, C$200,000 and C$300,000 debenture offerings in December 2012, January 2014, and January 2017, respectively, the Company entered into cross currency swaps, coterminous with the debentures, to effectively convert the Canadian dollar denominated offering into U.S. dollars. The Company designated the entire notional amount of the cross-currency fixed-for-fixed interest rate swap and related short-term U.S. dollar payables created by the monthly accruals of the swap settlement as a hedge of the foreign currency exposure of its net investment in the Renewable Energy Group's U.S. operations. The gain or loss related to the fair value changes of the swap and the related foreign currency gains and losses on the U.S. dollar accruals that are designated as, and are effective as, a hedge of the net investment in a foreign operation are reported in the same manner as the translation adjustment (in OCI) related to the net investment. A gain of $15,946 (2018 - loss of $41,244) was recorded in OCI in 2019.

(in thousands of U.S. dollars, except as noted and per share amounts)

24. Financial instruments (continued)

(b) Derivative instruments (continued)

(iv) Other derivatives

The Company provides energy requirements to various customers under contracts at fixed rates. While the production from the Tinker Hydroelectric Facility is expected to provide a portion of the energy required to service these customers, APUC anticipates having to purchase a portion of its energy requirements at the ISO NE spot rates to supplement self-generated energy.

This risk is mitigated through the use of short-term financial forward energy purchase contracts that are classified as derivative instruments. The electricity derivative contracts are net settled fixed-for-floating swaps whereby APUC pays a fixed price and receives the floating or indexed price on a notional quantity of energy over the remainder of the contract term at an average rate, as per the following table. These contracts are not accounted for as hedges and changes in fair value are recorded in earnings as they occur.

The Company is exposed to interest rate fluctuations related to certain of its floating rate debt obligations, including certain project-specific debt and its revolving credit facilities, its interest rate swaps as well as interest earned on its cash on hand.

The Company is exposed to foreign exchange fluctuations related to the portion of its dividend declared and payable in U.S. dollars. This risk is mitigated through the use of currency forward contracts. For the year ended December 31, 2019, a foreign exchange loss of $983 (2018 - gain of $1,115) was recorded in the consolidated statements of operations. These currency forward contracts are not accounted for as a hedge.

For derivatives that are not designated as hedges, the changes in the fair value are immediately recognized in earnings.

The effects on the consolidated statements of operations of derivative financial instruments not designated as hedges consist of the following:

	2019	2018
Change in unrealized loss (gain) on derivative financial instruments:		
Energy derivative contracts	**$ (530)**	$ 77
Currency forward contract	**904**	(1,230)
Total change in unrealized loss (gain) on derivative financial instruments	**$ 374**	$ (1,153)
Realized loss (gain) on derivative financial instruments:		
Energy derivative contracts	**227**	(73)
Currency forward contract	**(147)**	115
Total realized loss on derivative financial instruments	**$ 80**	$ 42
Loss (gain) on derivative financial instruments not accounted for as hedges	**454**	(1,111)
Discontinued hedge accounting (note 24(b)(ii)) and other	**(15,810)**	632
	$ (15,356)	$ (479)
Amounts recognized in the consolidated statements of operations consist of:		
Loss (gain) on derivative financial instruments	**$ (16,113)**	$ 636
Loss (gain) on foreign exchange	**757**	(1,115)
	$ (15,356)	$ (479)

(in thousands of U.S. dollars, except as noted and per share amounts)

24. Financial instruments (continued)

(c) Risk management

In the normal course of business, the Company is exposed to financial risks that potentially impact its operating results. The Company employs risk management strategies with a view of mitigating these risks to the extent possible on a cost effective basis. Derivative financial instruments are used to manage certain exposures to fluctuations in exchange rates, interest rates and commodity prices. The Company does not enter into derivative financial agreements for speculative purposes.

This note provides disclosures relating to the nature and extent of the Company's exposure to risks arising from financial instruments, including credit risk and liquidity risk, and how the Company manages those risks.

Credit risk

Credit risk is the risk of an unexpected loss if a customer or counterparty to a financial instrument fails to meet its contractual obligations. The Company's financial instruments that are exposed to concentrations of credit risk are primarily cash and cash equivalents, accounts receivable, notes receivable and derivative instruments. The Company limits its exposure to credit risk with respect to cash equivalents by ensuring available cash is deposited with its senior lenders, all of which have a credit rating of A or better. The Company does not consider the risk associated with the Renewable Energy Group accounts receivable to be significant as over 87% of revenue from power generation is earned from large utility customers having a credit rating of Baa2 or better by Moody's, or BBB or higher by S&P, or BBB or higher by DBRS. Revenue is generally invoiced and collected within 45 days.

The remaining revenue is primarily earned by the Regulated Services Group, which consists of water and wastewater, electric and gas utilities in the United States and Canada. In this regard, the credit risk related to the Regulated Services Group accounts receivable balances of $200,594 is spread over thousands of customers. The Company has processes in place to monitor and evaluate this risk on an ongoing basis including background credit checks and security deposits from new customers. In addition, the regulators of the Regulated Services Group allow for a reasonable bad debt expense to be incorporated in the rates and therefore recovered from rate payers.

As of December 31, 2019, the Company's maximum exposure to credit risk for these financial instruments was as follows:

	December 31, 2019	
	Canadian $	**US $**
Cash and cash equivalents and restricted cash	$ 53,619	$ 45,989
Accounts receivable	42,987	231,006
Allowance for doubtful accounts	(89)	(4,850)
Notes receivable	15,963	50,680
	$ 112,480	$ 322,825

In addition, the Company continuously monitors the creditworthiness of the counterparties to its foreign exchange, interest rate, and energy derivative contracts prior to settlement, and assesses each counterparty's ability to perform on the transactions set forth in the contracts. The counterparties consist primarily of financial institutions. This concentration of counterparties may impact the Company's overall exposure to credit risk, either positively or negatively, in that the counterparties may be similarly affected by changes in economic, regulatory or other conditions.

Liquidity risk

Liquidity risk is the risk that the Company will not be able to meet its financial obligations as they fall due. The Company's approach to managing liquidity risk is to ensure, to the extent possible, that it will always have sufficient liquidity to meet liabilities when due. As of December 31, 2019, in addition to cash on hand of $62,485, the Company had $1,047,216 available to be drawn on its senior debt facilities. Each of the Company's revolving credit facilities contain covenants that may limit amounts available to be drawn.

(in thousands of U.S. dollars, except as noted and per share amounts)

24. Financial instruments (continued)

(c) Risk management (continued)

Liquidity risk (continued)

The Company's liabilities mature as follows:

	Due less than 1 year	Due 2 to 3 years	Due 4 to 5 years	Due after 5 years	Total
Long-term debt obligations	$ 602,028	$ 468,740	$ 600,721	$2,260,416	$3,931,905
Convertible debentures	—	—	—	346	346
Advances in aid of construction	1,165	—	—	59,663	60,828
Interest on long-term debt	185,231	318,469	257,443	992,116	1,753,259
Purchase obligations	458,288	—	—	—	458,288
Environmental obligation	14,970	20,850	1,128	21,536	58,484
Derivative financial instruments:					
Cross-currency swap	4,149	69,099	3,851	4,666	81,765
Energy derivative and commodity contracts	1,631	909	—	359	2,899
Other obligations	39,115	2,120	2,696	109,094	153,025
Total obligations	$1,306,577	$ 880,187	$ 865,839	$3,448,196	$6,500,799

25. Comparative figures

Certain of the comparative figures have been reclassified to conform to the financial statement presentation adopted in the current year.

Management Discussion & Analysis

Management of Algonquin Power & Utilities Corp. ("APUC" or the "Company" or the "Corporation") has prepared the following discussion and analysis to provide information to assist its shareholders' understanding of the financial results for the three and twelve months ended December 31, 2019. This Management Discussion & Analysis ("MD&A") should be read in conjunction with APUC's annual audited consolidated financial statements for the years ended December 31, 2019 and 2018. This material is available on SEDAR at www.sedar.com, on EDGAR at www.sec.gov/edgar, and on the APUC website at www.AlgonquinPowerandUtilities.com. Additional information about APUC, including the most recent Annual Information Form ("AIF"), can be found on SEDAR at www.sedar.com and on EDGAR at www.sec.gov/edgar.

Unless otherwise indicated, financial information provided for the years ended December 31, 2019 and 2018 has been prepared in accordance with generally accepted accounting principles in the United States ("U.S. GAAP"). As a result, the Company's financial information may not be comparable with financial information of other Canadian companies that provide financial information on another basis.

All monetary amounts are in thousands of U.S. dollars, except where otherwise noted. We denote any amounts denominated in Canadian dollars with "C$" immediately prior to the stated amount.

This MD&A is based on information available to management as of February 27, 2020.

Contents

Caution Concerning Forward-Looking Statements, Forward-Looking Information and Non-GAAP Measures

Forward-Looking Statements and Forward-Looking Information

This document may contain statements that constitute "forward-looking information" within the meaning of applicable securities laws in each of the provinces of Canada and the respective policies, regulations and rules under such laws or "forward-looking statements" within the meaning of the U.S. Private Securities Litigation Reform Act of 1995 (collectively, “forward-looking information”). The words “anticipates”, “believes”, “budget”, “could”, “estimates”, “expects”, “forecasts”, “intends”, “may”, “might”, “plans”, “projects”, “schedule”, “should”, “will”, “would” and similar expressions are often intended to identify forward-looking information, although not all forward-looking information contains these identifying words. Specific forward-looking information in this document includes, but is not limited to, statements relating to: expected future growth and results of operations; liquidity, capital resources and operational requirements; rate reviews, including resulting decisions and rates and expected impacts and timing; sources of funding, including adequacy and availability of credit facilities, debt maturation and future borrowings; expectations regarding the use of proceeds from equity financing, including the Offering and the ATM Program (each as defined herein); ongoing and planned acquisitions, projects and initiatives, including expectations regarding costs, financing, results and completion dates; expectations regarding the anticipated closing of APUC's acquisitions of Ascendant and New York American Water (each as defined herein); expectations regarding the Company's corporate development activities and the results thereof including the expected business mix between the Regulated Services Group and Renewable Energy Group; expectations regarding regulatory hearings, motions and approvals; expectations regarding the cost of operations, capital spending and maintenance, and the variability of those costs; expected future capital investments, including expected timing, investment plans, sources of funds and impacts; expectations regarding generation availability, capacity and production; expectations regarding the outcome of existing or potential legal and contractual claims and disputes; expectations regarding the ability to access the capital market on reasonable terms; strategy and goals; expectations regarding succession planning; contractual obligations and other commercial commitments; environmental liabilities; dividends to shareholders; expectations regarding the maturity and redemption of APUC's outstanding subordinated notes; expectations regarding the impact of tax reforms; credit ratings; anticipated growth and emerging opportunities in APUC’s target markets; accounting estimates; interest rates; currency exchange rates; and commodity prices. All forward-looking information is given pursuant to the “safe harbor” provisions of applicable securities legislation.

The forecasts and projections that make up the forward-looking information contained herein are based on certain factors or assumptions which include, but are not limited to: the receipt of applicable regulatory approvals and requested rate decisions; the absence of material adverse regulatory decisions being received and the expectation of regulatory stability; the absence of any material equipment breakdown or failure; availability of financing on commercially reasonable terms and the stability of credit ratings of the Corporation and its subsidiaries; the absence of unexpected material liabilities or uninsured losses; the continued availability of commodity supplies and stability of commodity prices; the absence of sustained interest rate increases or significant currency exchange rate fluctuations; the absence of significant operational or supply chain disruptions or liability due to natural disasters, diseases or catastrophic events; the continued ability to maintain systems and facilities to ensure their continued performance; the absence of a severe and prolonged downturn in general economic, credit, social and market conditions; the successful and timely development and construction of new projects; the absence of material capital project or financing cost overruns; sufficient liquidity and capital resources; the continuation of observed weather patterns and trends; the absence of significant counterparty defaults; the continued competitiveness of electricity pricing when compared with alternative sources of energy; the realization of the anticipated benefits of the Corporation’s acquisitions and joint ventures; the absence of a material change in political conditions or public policies and directions by governments materially negatively affecting the Corporation; the ability to obtain and maintain licenses and permits; the absence of a material decrease in market energy prices; the absence of material disputes with taxation authorities or changes to applicable tax laws; continued maintenance of information technology infrastructure and the absence of a material breach of cyber security; favourable relations with external stakeholders; and favourable labour relations.

The forward-looking information contained herein is subject to risks, uncertainties and other factors that could cause actual results to differ materially from historical results or results anticipated by the forward-looking information. Factors which could cause results or events to differ materially from current expectations include, but are not limited to: changes in general economic, credit, social and market conditions; changes in customer energy usage patterns and energy demand; global climate change; the incurrence of environmental liabilities; natural disasters and other catastrophic events; the failure of information technology infrastructure and cybersecurity; the loss of key personnel and/or labour disruptions; seasonal fluctuations and variability in weather conditions and natural resource availability; reductions in demand for electricity, gas and water due to developments in technology; reliance on transmission systems owned and operated by third parties; issues arising with respect to land use rights and access to the Corporation’s facilities; critical equipment breakdown or failure; terrorist attacks; fluctuations in commodity prices; capital expenditures; reliance on subsidiaries; the incurrence of an uninsured loss; a credit rating downgrade; an increase in financing costs or limits on access to credit and capital markets; sustained increases in interest rates; currency exchange rate fluctuations; restricted financial flexibility due to covenants in existing credit agreements; an inability to refinance maturing debt on commercially reasonable terms; disputes with taxation authorities or changes to applicable tax laws; failure to identify, acquire, develop or timely place in service projects to maximize the value of production tax credit qualified equipment; requirement for greater than expected contributions to post-employment benefit plans; default by a counterparty; inaccurate assumptions, judgments and/or estimates with respect to asset retirement obligations; failure to maintain required regulatory authorizations; changes to health and safety laws, regulations or permit requirements; failure to comply with and/or changes to environmental laws, regulations and other standards; compliance with new foreign laws or regulations; failure to identify attractive acquisition or development candidates necessary to pursue the Corporation’s growth strategy; delays and cost overruns in the design and construction of projects, including as a result of the 2019 novel coronavirus outbreak in China (the "2019 Novel Coronavirus"); loss of key customers; failure to realize the anticipated benefits of acquisitions or joint ventures; Atlantica (as defined herein) or the Corporation’s joint venture with Abengoa S.A (MC:ABG) ("Abengoa"), Abengoa-Algonquin Global Energy Solutions ("AAGES"), acting in a manner contrary to the Corporation’s interests; a drop in the market value of Atlantica's ordinary shares; facilities being condemned or otherwise taken by governmental entities; increased external-stakeholder activism adverse to the Corporation’s interests; and fluctuations in the price and liquidity of the Corporation’s common shares. Although the Corporation has attempted to identify important factors that could cause actual actions, events or results to differ materially from those described in forward-looking information, there may be other factors that cause actions, events or results not to be as anticipated, estimated or intended. Some of these and other factors are discussed in more detail under the heading “*Enterprise Risk Management*” and in the Corporation's most recent AIF.

Forward-looking information contained herein is made as of the date of this document and based on the plans, beliefs, estimates, projections, expectations, opinions and assumptions of management on the date hereof. There can be no assurance that forward-looking information will prove to be accurate, as actual results and future events could differ materially from those anticipated in such forward-looking information. Accordingly, readers should not place undue reliance on forward-looking information. While subsequent events and developments may cause the Corporation’s views to change, the Corporation disclaims any obligation to update any forward-looking information or to explain any material difference between subsequent actual events and such forward-looking information, except to the extent required by law. All forward-looking information contained herein is qualified by these cautionary statements.

Non-GAAP Financial Measures

The terms “Adjusted Net Earnings”, “Adjusted Earnings Before Interest, Taxes, Depreciation and Amortization” (“Adjusted EBITDA”), “Adjusted Funds from Operations”, "Net Energy Sales", "Net Utility Sales" and "Divisional Operating Profit" are used throughout this MD&A. The terms “Adjusted Net Earnings”, “Adjusted Funds from Operations”, "Adjusted EBITDA", "Net Energy Sales", "Net Utility Sales" and "Divisional Operating Profit" are not recognized measures under U.S. GAAP. There is no standardized measure of “Adjusted Net Earnings”, "Adjusted EBITDA", “Adjusted Funds from Operations”, "Net Energy Sales", "Net Utility Sales", and "Divisional Operating Profit"; consequently, APUC’s method of calculating these measures may differ from methods used by other companies and therefore may not be comparable to similar measures presented by other companies. A calculation and analysis of “Adjusted Net Earnings”, "Adjusted EBITDA", “Adjusted Funds from Operations”, "Net Energy Sales", "Net Utility Sales", and "Divisional Operating Profit" can be found throughout this MD&A.

<u>Adjusted EBITDA</u>

Adjusted EBITDA is a non-GAAP measure used by many investors to compare companies on the basis of ability to generate cash from operations. APUC uses these calculations to monitor the amount of cash generated by APUC as compared to the amount of dividends paid by APUC. APUC uses Adjusted EBITDA to assess the operating performance of APUC without the effects of (as applicable): depreciation and amortization expense, income tax expense or recoveries, acquisition costs, litigation expenses, interest expense, gain or loss on derivative financial instruments, write down of intangibles and property, plant and equipment, earnings attributable to non-controlling interests, non-service pension and post-employment costs, cost related to tax equity financing, gain or loss on foreign exchange, earnings or loss from discontinued operations, changes in value of investments carried at fair value, and other typically non-recurring items. APUC adjusts for these factors as they may be non-cash, unusual in nature and are not factors used by management for evaluating the operating performance of the Company. APUC believes that presentation of this measure will enhance an investor’s understanding of APUC’s operating performance. Adjusted EBITDA is not intended to be representative of cash provided by operating activities or results of operations determined in accordance with U.S. GAAP, and can be impacted positively or negatively by these items.

<u>Adjusted Net Earnings</u>

Adjusted Net Earnings is a non-GAAP measure used by many investors to compare net earnings from operations without the effects of certain volatile primarily non-cash items that generally have no current economic impact or items such as acquisition expenses or litigation expenses that are viewed as not directly related to a company’s operating performance. APUC uses Adjusted Net Earnings to assess its performance without the effects of (as applicable): gains or losses on foreign exchange, foreign exchange forward contracts, interest rate swaps, acquisition costs, one-time costs of arranging tax equity financing, litigation expenses and write down of intangibles and property, plant and equipment, earnings or loss from discontinued operations, unrealized mark-to-market revaluation impacts (other than those realized in connection with the sales of development assets), changes in value of investments carried at fair value, and other typically non-recurring items as these are not reflective of the performance of the underlying business of APUC. The Non-cash accounting charge related to the revaluation of U.S. deferred income tax assets and liabilities as a result of implementation of the effects of the Tax Cuts and Jobs Act ("U.S. Tax Reform") is adjusted as it is also considered a non-recurring item not reflective of the performance of the underlying business of APUC. APUC believes that analysis and presentation of net earnings or loss on this basis will enhance an investor's understanding of the operating performance of its businesses. Adjusted Net Earnings is not intended to be representative of net earnings or loss determined in accordance with U.S. GAAP, and can be impacted positively or negatively by these items.

Adjusted Funds from Operations

Adjusted Funds from Operations is a non-GAAP measure used by investors to compare cash flows from operating activities without the effects of certain volatile items that generally have no current economic impact or items such as acquisition expenses that are viewed as not directly related to a company's operating performance. APUC uses Adjusted Funds from Operations to assess its performance without the effects of (as applicable): changes in working capital balances, acquisition expenses, litigation expenses, cash provided by or used in discontinued operations and other typically non-recurring items affecting cash from operations as these are not reflective of the long-term performance of the underlying businesses of APUC. APUC believes that analysis and presentation of funds from operations on this basis will enhance an investor's understanding of the operating performance of its businesses. Adjusted Funds from Operations is not intended to be representative of cash flows from operating activities as determined in accordance with U.S. GAAP, and can be impacted positively or negatively by these items.

Net Energy Sales

Net Energy Sales is a non-GAAP measure used by investors to identify revenue after commodity costs used to generate revenue where such revenue generally increases or decreases in response to increases or decreases in the cost of the commodity used to produce that revenue. APUC uses Net Energy Sales to assess its revenues without the effects of fluctuating commodity costs as such costs are predominantly passed through either directly or indirectly in the rates that are charged to customers. APUC believes that analysis and presentation of Net Energy Sales on this basis will enhance an investor's understanding of the revenue generation of its businesses. It is not intended to be representative of revenue as determined in accordance with U.S. GAAP.

Net Utility Sales

Net Utility Sales is a non-GAAP measure used by investors to identify utility revenue after commodity costs, either natural gas or electricity, where these commodity costs are generally included as a pass through in rates to its utility customers. APUC uses Net Utility Sales to assess its utility revenues without the effects of fluctuating commodity costs as such costs are predominantly passed through and paid for by utility customers. APUC believes that analysis and presentation of Net Utility Sales on this basis will enhance an investor's understanding of the revenue generation of its utility businesses. It is not intended to be representative of revenue as determined in accordance with U.S. GAAP.

Divisional Operating Profit

Divisional Operating Profit is a non-GAAP measure. APUC uses Divisional Operating Profit to assess the operating performance of its business groups without the effects of (as applicable): depreciation and amortization expense, corporate administrative expenses, income tax expense or recoveries, acquisition costs, litigation expenses, interest expense, gain or loss on derivative financial instruments, write down of intangibles and property, plant and equipment, gain or loss on foreign exchange, earnings or loss from discontinued operations, non-service pension and post-employment costs, and other typically non-recurring items. APUC adjusts for these factors as they may be non-cash, unusual in nature and are not factors used by management for evaluating the operating performance of the divisional units. Divisional Operating Profit is calculated inclusive of interest, dividend and equity income earned from indirect investments, and Hypothetical Liquidation at Book Value ("HLBV") income, which represents the value of net tax attributes earned in the period from electricity generated by certain of its U.S. wind power and U.S. solar generation facilities. APUC believes that presentation of this measure will enhance an investor's understanding of APUC's divisional operating performance. Divisional Operating Profit is not intended to be representative of cash provided by operating activities or results of operations determined in accordance with U.S. GAAP.

Capitalized terms used herein and not otherwise defined will have the meanings assigned to them in the Company's most recent AIF.

Overview and Business Strategy

APUC is incorporated under the *Canada Business Corporations Act*. APUC owns and operates a diversified portfolio of regulated and non-regulated generation, distribution, and transmission utility assets which are expected to deliver predictable earnings and cash flows. APUC seeks to maximize total shareholder value through real per share growth in earnings and cash flows to support a growing dividend and share price appreciation. APUC strives to achieve these results while also seeking to maintain a business risk profile consistent with its BBB flat investment grade credit ratings and a strong focus on Environmental, Social and Governance factors.

APUC's current quarterly dividend to shareholders is $0.1410 per common share or $0.5640 per common share per annum. Based on exchange rates as at February 26, 2020, the quarterly dividend is equivalent to C$0.1876 per common share or C$0.7504 per common share per annum. APUC believes its annual dividend payout allows for both an immediate return on investment for shareholders and retention of sufficient cash within APUC to fund growth opportunities. Changes in the level of dividends paid by APUC are at the discretion of the APUC Board of Directors (the "Board"), with dividend levels being reviewed periodically by the Board in the context of APUC's financial performance and growth prospects.

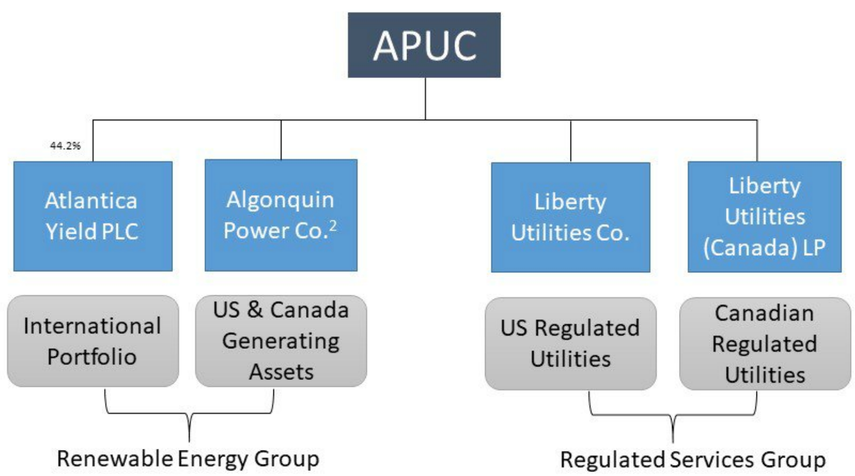
APUC's operations are organized across two primary business units consisting of: the Regulated Services Group, which primarily owns and operates a portfolio of regulated assets in the United States and Canada, and the Renewable Energy Group, which primarily owns and operates a diversified portfolio of renewable generation assets.

APUC pursues investment opportunities with an objective of maintaining the current business mix between its Regulated Services Group and Renewable Energy Group and with leverage consistent with its current credit ratings[1]. The business mix target may from time to time require APUC to grow its Regulated Services Group or implement other strategies in order to pursue investment opportunities within its Renewable Energy Group.

The Company also undertakes development activities for both business units, working with a global reach to identify, develop, acquire, or invest in renewable power generating facilities, regulated utilities and other complementary infrastructure projects. See additional discussion in *Corporate Development Activities*.

Summary Organizational Structure

The following represents a summarized organizational chart for APUC. A more detailed description of APUC's organizational structure can be found in the most recent AIF.



1 See *Treasury Risk Management -Downgrade in the Company's Credit Rating Risk*

2 Algonquin Power Co. dba Liberty Power

Regulated Services Group

The Regulated Services Group operates a diversified portfolio of regulated utility systems throughout the United States and Canada serving approximately 804,000 connections. The Regulated Services Group seeks to provide safe, high quality, and reliable services to its customers and to deliver stable and predictable earnings to APUC. In addition to encouraging and supporting organic growth within its service territories, the Regulated Services Group seeks to deliver continued growth in earnings through accretive acquisitions of additional utility systems.

The Regulated Services Group's regulated electrical distribution utility systems and related generation assets are located in the States of California, New Hampshire, Missouri, Kansas, Oklahoma, and Arkansas which together serve approximately 267,000 electric connections. The group also owns and manages generating assets with a gross capacity of approximately 1.7 GW and has investments in generating assets with approximately 0.3 GW of net generation capacity.

The Regulated Services Group's regulated natural gas distribution utility systems are located in the States of Georgia, Illinois, Iowa, Massachusetts, New Hampshire, Missouri, New York, and the Province of New Brunswick which together serve approximately 369,000 natural gas connections.

The Regulated Services Group's regulated water distribution and wastewater collection utility systems are located in the States of Arizona, Arkansas, California, Illinois, Missouri, and Texas which together serve approximately 168,000 connections.

Renewable Energy Group

The Renewable Energy Group generates and sells electrical energy produced by its diverse portfolio of renewable power generation and clean power generation facilities primarily located across the United States and Canada. The Renewable Energy Group seeks to deliver continuing growth through development of new greenfield power generation projects and accretive acquisitions of additional electrical energy generation facilities.

The Renewable Energy Group owns and operates hydroelectric, wind, solar, and thermal facilities with a combined gross generating capacity of approximately 1.5 GW. Approximately 84% of the electrical output is sold pursuant to long term contractual arrangements which as of December 31, 2019 had a production-weighted average remaining contract life of approximately 14 years.

In addition to directly owned and operated assets, APUC also holds a 44.2% interest in Atlantica Yield PLC ("Atlantica"). Atlantica owns and operates a portfolio of international clean energy and water infrastructure assets under long term contracts with a Cash Available for Distribution (CAFD) weighted average remaining contract life of approximately 18 years as of December 31, 2019.

2019 Major Highlights

Corporate Highlights

Operating Results

APUC operating results relative to the same period last year are as follows:

(all dollar amounts in $ millions except per share information)	Three Months Ended December 31			Twelve Months Ended December 31		
	2019	2018	Change	2019	2018	Change
Net earnings attributable to shareholders	**$172.1**	$44.0	**291%**	**$530.9**	$185.0	**187%**
Adjusted Net Earnings[1]	**$103.6**	$70.5	**47%**	**$321.3**	$312.2	**3%**
Adjusted EBITDA[1]	**$231.5**	$198.9	**16%**	**$838.6**	$804.4	**4%**
Net earnings per common share	**$0.34**	$0.09	**278%**	**$1.05**	$0.38	**176%**
Adjusted Net Earnings per common share[1]	**$0.20**	$0.14	**43%**	**$0.63**	$0.66	**(5)%**

1 See *Non-GAAP Financial Measures*.

Declaration of 2020 First Quarter Dividend of $0.1410 (C$0.1876) per Common Share

APUC currently targets annual growth in dividends payable to shareholders underpinned by increases in earnings and cash flow. In setting the appropriate dividend level, the Board of APUC considers the Company's current and expected growth in earnings per share as well as a dividend payout ratio as a percentage of earnings per share and cash flow per share.

On February 27, 2020, APUC announced that the Board of APUC declared a first quarter 2020 dividend of $0.1410 per common share payable on April 15, 2020 to shareholders of record on March 31, 2020. Based on the prior day Bank of Canada exchange rate, the Canadian dollar equivalent for the first quarter 2020 dividend is set at C$0.1876 per common share.

The previous four quarter equivalent Canadian dollar dividends per common share have been as follows:

	Q2 2019	Q3 2019	Q4 2019	Q1 2020	Total
U.S. dollar dividend	$0.1410	$0.1410	$0.1410	$0.1410	$0.5640
Canadian dollar equivalent	$0.1899	$0.1878	$0.1858	$0.1876	$0.7511

Corporate Financings Completed

Issuance of Fixed-to-Floating Subordinated Notes

On May 23, 2019, APUC issued $350.0 million of 60 (non-call 5) year fixed-to-floating 6.20% subordinated notes ("Notes"). Concurrent with the offering, APUC entered into a cross currency swap to convert the U.S. dollar denominated coupon and principal payments from the offering into Canadian dollars, resulting in an effective interest rate to the Company throughout the fixed-rate period of the Notes of approximately 5.96%. This offering represents APUC's second issuance into the U.S. public debt markets (see *Long Term Debt*).

Common Equity Financing

In October 2019, APUC sold approximately 26.3 million of its common shares at a price of $13.50 by way of an underwritten marketed public offering (the "Offering") for total gross proceeds of approximately $354.4 million. The Offering primarily targeted U.S. investors. The proceeds of the Offering were or will be used (as applicable) to partially finance certain of the Company's previously announced acquisitions, to partially finance the Company's renewable development growth projects, and for general corporate purposes.

Regulated Services Group Highlights

Definitive Agreement to Acquire Bermuda Electric Light Company

On June 3, 2019, APUC announced it had agreed to acquire the Ascendant Group Limited ("Ascendant") (BSX: AGL.BH) for a purchase price of $36.00 per common share, representing an aggregate share purchase price of approximately $365.0 million (the "Ascendant Transaction"). Ascendant, through its major subsidiary, Bermuda Electric Light Company ("BELCO"), is the sole electric utility providing safe and reliable regulated electrical generation, transmission and distribution services to approximately 63,000 residents and businesses in Bermuda. Approval of Ascendant's common shareholders has been received and the closing of the Ascendant Transaction is expected to occur in 2020 subject to customary closing conditions, including the receipt of certain regulatory and government approvals in Bermuda.

Acquisition of Ownership Interest in Wataynikaneyap Power Transmission Project

On January 17, 2019, the Regulated Services Group acquired from Fortis Inc. a 9.8% ownership interest in an electricity transmission project located in Northwestern Ontario (the "Wataynikaneyap Power Transmission Project") that is expected to connect 17 remote First Nation communities to the Ontario provincial electricity grid through the construction of approximately 1,800 km of transmission lines. In addition to providing participating First Nations communities ownership in the transmission line, the Wataynikaneyap Power Transmission Project is expected to result in socio-economic benefits for surrounding communities, reduce environmental risk, and lessen greenhouse gas emissions associated with diesel-fired generation currently used in that area.

In April 2019, the Ontario Energy Board approved the leave-to-construct application. Completion of construction financing and issuance of notice to proceed to the EPC contractor occurred in October 2019. The Wataynikaneyap Power Transmission Project is targeted to be complete by the end of 2023.

Significant Milestones Achieved on Mid-West Wind Development Project

In June 2019, the Regulated Services Group received certificates of convenience and necessity ("CC&N") to acquire, once completed, three wind farms generating up to 600 MW of wind energy located in Barton, Dade, Lawrence, and Jasper Counties in Missouri and in Neosho County, Kansas.

Receipt of the CC&N's allows construction to commence on the three wind generation sites. Construction of two of the wind farms began in the fourth quarter of 2019 and construction on the third wind farm began in the first quarter of 2020 (see *Corporate Development Activities*).

Acquisition of New Brunswick Gas

On October 1, 2019, APUC completed the acquisition of the Enbridge Gas New Brunswick Limited Partnership ("New Brunswick Gas" or the "New Brunswick Gas System") for approximately C$339.0 million. New Brunswick Gas is a regulated utility that provides natural gas to approximately 12,000 customers in 12 communities across New Brunswick, and operates approximately 1,200 km of natural gas distribution pipeline.

Issuance of C$200 of senior unsecured debentures

Subsequent to year-end on February 14, 2020, Liberty Utilities (Canada) LP, the holding company of New Brunswick Gas, issued C$200.0 million of senior unsecured debentures bearing interest at 3.315% and with a maturity date of February 14, 2050. The debentures received a rating of BBB from DBRS. The proceeds were used to repay corporate credit facilities drawn in connection with the closing of New Brunswick Gas (see *Long Term Debt*).

Acquisition of St. Lawrence Gas

On November 1, 2019, the Regulated Services Group completed the acquisition of the St. Lawrence Gas Company Inc. ("St. Lawrence Gas" or the "St. Lawrence Gas System") for approximately $61.8 million. St. Lawrence Gas is a regulated utility that provides natural gas to approximately 17,000 customers in the state of New York and operates approximately 1,100 km of natural gas distribution pipeline.

Definitive Agreement to Acquire New York American Water

On November 20, 2019, APUC announced that it entered into a stock purchase agreement with American Water Works Company, Inc. (NYSE: AWK) ("American Water"), to purchase American Water's regulated operations in the State of New York ("New York American Water") for a purchase price of $608.0 million, subject to customary adjustments. New York American Water is a regulated water and wastewater utility serving over 125,000 customer connections across seven counties in southeastern New York. Operations include approximately 1,270 miles of water mains and distributions lines with 98% of customers located in Nassau County on Long Island. The transaction remains subject to regulatory approval and other typical closing conditions and is expected to close sometime in 2021.

Successful Rate Review Outcomes

A core strategy of the Regulated Services Group is to ensure an appropriate return is earned on the rate base at its various utility systems. During 2019, the Regulated Services Group successfully completed several rate reviews representing a cumulative annualized revenue increase of approximately $8.5 million. In addition progress was made in advancing several regulatory mechanisms.

Renewable Energy Group's Highlights

Issuance of Green Bonds

On January 29, 2019, the Renewable Energy Group issued C$300.0 million of senior unsecured debentures bearing interest at 4.60% and with a maturity date of January 29, 2029. The debentures represent the Renewable Energy Group's inaugural "green bond" offering (see *Long Term Debt*).

Maverick Creek Wind Project Joint Venture

On August 8, 2019, the Renewable Energy Group agreed to jointly develop the approximately 490 MW Maverick Creek Wind Project located in Concho County, Texas with Renewable Energy Systems Americas Inc.

2019 Fourth Quarter Results From Operations

Key Financial Information	Three Months Ended December 31	
(all dollar amounts in $ millions except per share information)	**2019**	**2018**
Revenue	**$ 439.7**	$ 421.9
Net earnings attributable to shareholders	**172.1**	44.0
Cash provided by operating activities	**167.5**	168.6
Adjusted Net Earnings[1]	**103.6**	70.5
Adjusted EBITDA[1]	**231.5**	198.9
Adjusted Funds from Operations[1]	**144.1**	132.5
Dividends declared to common shareholders	**74.3**	63.1
Weighted average number of common shares outstanding	**519,846,220**	477,450,181
Per share		
Basic net earnings	**$ 0.34**	$ 0.09
Diluted net earnings	**$ 0.33**	$ 0.09
Adjusted Net Earnings[1,2]	**$ 0.20**	$ 0.14
Dividends declared to common shareholders	**$ 0.14**	$ 0.13

1 See *Non-GAAP Financial Measures*.

2 APUC uses per share Adjusted Net Earnings to enhance assessment and understanding of the performance of APUC.

For the three months ended December 31, 2019, APUC experienced an average exchange rate of Canadian to U.S. dollars of approximately 0.7576 as compared to 0.7568 in the same period in 2018. As such, any quarter over quarter variance in revenue or expenses, in local currency, at any of APUC's Canadian entities is affected by a change in the average exchange rate upon conversion to APUC's reporting currency.

For the three months ended December 31, 2019, APUC reported total revenue of $439.7 million as compared to $421.9 million during the same period in 2018, an increase of $17.8 million. The major factors resulting in the increase in APUC revenue in the three months ended December 31, 2019 as compared to the corresponding period in 2018 are set out as follows:

(all dollar amounts in $ millions)	Three Months Ended December 31	
Comparative Prior Period Revenue	**$**	**421.9**
REGULATED SERVICES GROUP		
Existing Facilities		
Electricity: Decrease is primarily due to lower pass through commodity costs and lower consumption as a result of warmer weather compared to the prior year at the Empire Electric and Granite State Electric Systems.		(11.6)
Gas: Decrease is primarily due to lower pass through commodity costs at the Midstates, EnergyNorth, New England and Empire Gas Systems.		(8.7)
Water: Increase is primarily due to higher revenues resulting from organic growth at the White Hall and Litchfield Park Water Systems.		1.8
Other: Increase in contracted services from Ft. Benning.		2.8
		(15.7)
New Facilities		
Gas: Acquisitions of New Brunswick Gas (October 2019) and St. Lawrence Gas (November 2019).		24.5
		24.5
Rate Reviews		
Electricity: Implementation of new rates at the Granite State Electric System.		0.3
Water: Implementation of lower rates at the Park Water System due to U.S. Tax Reform, partially offset by higher rates at the Tall Timbers Water System, net of U.S. Tax Reform impact.		(0.2)
		0.1
RENEWABLE ENERGY GROUP		
Existing Facilities		
Hydro: Decrease is primarily due to lower production at the Quebec and Ontario Regions.		(1.0)
Wind Canada: Increase is primarily due to annual rate increases and higher production at the St. Leon Wind Facility.		1.1
Wind U.S.: Increase is primarily due to higher production.		1.8
Solar U.S.: Increase is primarily due to higher production at the Bakersfield Solar Facilities as well as favorable Renewable Energy Credit ("REC") pricing at Great Bay Solar Facility.		0.6
Thermal: Decrease is primarily due to lower production and unfavorable capacity pricing at the Windsor Locks Thermal Facility.		(1.7)
Other		0.4
		1.2
New Facilities		
Wind Canada: The Amherst Island Wind Facility was previously accounted for as an equity investment.		7.7
		7.7
Current Period Revenue	**$**	**439.7**

A more detailed discussion of these factors is presented within the business unit analysis.

For the three months ended December 31, 2019, net earnings attributable to shareholders totaled $172.1 million as compared to $44.0 million during the same period in 2018, an increase of $128.1 million or 291.1%. The increase was due to a $21.3 million increase in earnings from operating facilities, a $144.1 million change in fair value of investments carried at fair value, a $10.6 million increase in interest, dividend, equity and other income, a $9.4 million increase in net effect of non-controlling interests and a $0.2 million increase in gains from derivative instruments. These items were partially offset by a $7.1 million increase in interest expense, a $13.9 million increase in depreciation and amortization expenses, a $15.3 million increase in acquisition related costs, a $5.0 million increase in pension and post-employment non-service costs, a $0.2 million increase in administration charges, a $2.4 million increase in foreign exchange losses, and a $9.7 million increase in income tax expense (tax explanations are discussed in *APUC: Corporate and Other Expenses)* as compared to the same period in 2018.

During the three months ended December 31, 2019, cash provided by operating activities totaled $167.5 million as compared to $168.6 million during the same period in 2018. During the three months ended December 31, 2019, Adjusted Funds from Operations totaled $144.1 million as compared to Adjusted Funds from Operations of $132.5 million during the same period in 2018 (see *Non-GAAP Financial Measures*).

During the three months ended December 31, 2019, Adjusted EBITDA totaled $231.5 million as compared to $198.9 million during the same period in 2018, an increase of $32.6 million or 16.4%. A more detailed analysis of these factors is presented within the reconciliation of Adjusted EBITDA to net earnings set out below (see *Non-GAAP Financial Measures*).

2019 Annual Results From Operations

Key Financial Information

(all dollar amounts in $ millions except per share information)	Twelve Months Ended December 31 2019	2018	2017
Revenue	**$ 1,624.9**	$ 1,648.5	$ 1,521.9
Net earnings attributable to shareholders	**530.9**	185.0	149.5
Cash provided by operating activities	**611.3**	530.4	326.6
Adjusted Net Earnings[1]	**321.3**	312.2	225.0
Adjusted EBITDA[1]	**838.6**	804.4	689.4
Adjusted Funds from Operations[1]	**566.2**	554.1	477.1
Dividends declared to common shareholders	**277.8**	235.4	185.9
Weighted average number of common shares outstanding	**499,910,876**	461,818,023	382,323,434
Per share			
Basic net earnings	**$ 1.05**	$ 0.38	$ 0.37
Diluted net earnings	**$ 1.04**	$ 0.38	$ 0.37
Adjusted Net Earnings[1,2]	**$ 0.63**	$ 0.66	$ 0.57
Dividends declared to common shareholders	**$ 0.55**	$ 0.50	$ 0.47
Total assets	**10,911.5**	9,398.6	8,395.6
Long term debt[3]	**3,932.2**	3,337.3	3,080.5

1 See *Non-GAAP Financial Measures*.

2 APUC uses per share Adjusted Net Earnings to enhance assessment and understanding of the performance of APUC.

3 Includes current and long-term portion of debt and convertible debentures per the financial statements.

For the twelve months ended December 31, 2019, APUC experienced an average exchange rate of Canadian to U.S. of approximately 0.7537 as compared to 0.7715 in the same period in 2018. As such, any year-over-year variance in revenue or expenses, in local currency, at any of APUC's Canadian entities is affected by a change in the average exchange rate upon conversion to APUC's reporting currency.

For the twelve months ended December 31, 2019, APUC reported total revenue of $1,624.9 million as compared to $1,648.5 million during the same period in 2018, a decrease of $23.6 million or 1.4%. The major factors resulting in the decrease in APUC revenue for the twelve months ended December 31, 2019 as compared to the corresponding period in 2018 are set out as follows:

(all dollar amounts in $ millions)	Twelve Months Ended December 31
Comparative Prior Period Revenue	**$ 1,648.5**
REGULATED SERVICES GROUP	
Existing Facilities	
Electricity: Decrease is primarily due to lower pass through commodity costs at the Empire Electric System.	(33.8)
Gas: Decrease is primarily due to lower pass through commodity costs at the Midstates, EnergyNorth, New England and Empire Gas Systems.	(21.8)
Water: Increase is primarily due to higher revenues resulting from organic growth at the Litchfield Park Water System as well as the acquisition of several small water utilities throughout the year.	2.6
Other: Increase in contracted services from Ft. Benning.	2.6
	(50.4)
New Facilities	
Gas: Acquisitions of New Brunswick Gas (October 2019) and St. Lawrence Gas (November 2019).	24.5
	24.5
Rate Reviews	
Electricity: Implementation of lower rates at the Empire Electric System due to U.S. Tax Reform.	(13.0)
Gas: Implementation of new rates, net of U.S. Tax Reform impact, primarily at the Midstates and EnergyNorth Gas Systems, partially offset by lower rates at the Empire Gas System due to U.S. Tax Reform.	5.0
Water: Implementation of lower rates at the Park Water System due to U.S. Tax Reform, partially offset by new rates, net of U.S. Tax Reform impact, at the Litchfield Park Water System.	(0.6)
	(8.6)
RENEWABLE ENERGY GROUP	
Existing Facilities	
Hydro: Increase is primarily due to higher production.	0.2
Wind Canada: Increase is primarily due to annual rate increases and higher production at the St. Leon Wind Facility.	2.1
Wind U.S.: Increase is primarily due to higher production, partially offset by unfavorable market pricing during periods with low wind resources at the Senate Wind Facility as well as lower REC rates at the Minonk Wind Facility.	0.4
Solar Canada: Increase is primarily due to higher production.	0.2
Thermal: Decrease is primarily due lower production.	(8.7)
Other	0.5
	(5.3)
New Facilities	
Wind Canada: Amherst Island Wind Facility achieved commercial operations ("COD") in June 2018.	15.9
Solar U.S.: Great Bay Solar Facility achieved full COD in March 2018.	2.0
	17.9
Foreign Exchange	**(1.7)**
Current Period Revenue	**$ 1,624.9**

A more detailed discussion of these factors is presented within the business unit analysis.

For the twelve months ended December 31, 2019, net earnings attributable to shareholders totaled $530.9 million as compared to $185.0 million during the same period in 2018, an increase of $345.9 million. The increase was due to a $17.7 million increase in earnings from operating facilities, a $67.9 million increase in interest, dividend, equity and other income, a $416.1 million change in fair value of investments carried at fair value, and a $16.7 million increase on gains from derivative instruments. These items were partially offset by a $29.4 million increase in interest expense, a $23.5 million increase in depreciation and amortization expenses, a $12.3 million increase in pension and post-employment non-service costs, a $10.9 million increase in acquisition costs, a $4.1 million increase in administration charges, a $12.4 million increase in other losses, a $3.2 million increase in foreign exchange losses, a $60.0 million decrease in net effect of non-controlling interests, and a $16.7 million increase in income tax expense (tax explanations are discussed in *APUC: Corporate and Other Expenses*).

During the twelve months ended December 31, 2019, cash provided by operating activities totaled $611.3 million as compared to $530.4 million during the same period in 2018. During the twelve months ended December 31, 2019, Adjusted Funds from Operations, totaled $566.2 million as compared to $554.1 million the same period in 2018, an increase of $12.1 million (see *Non-GAAP Financial Measures*).

Adjusted EBITDA in the twelve months ended December 31, 2019 totaled $838.6 million as compared to $804.4 million during the same period in 2018, an increase of $34.2 million or 4.3%. A detailed analysis of this variance is presented within the reconciliation of Adjusted EBITDA to net earnings set out below (see *Non-GAAP Financial Measures*).

2019 Adjusted EBITDA Summary

Adjusted EBITDA (see *Non-GAAP Financial Measures*) for the three months ended December 31, 2019 totaled $231.5 million as compared to $198.9 million during the same period in 2018, an increase of $32.6 million or 16.4%. Adjusted EBITDA for the twelve months ended December 31, 2019 totaled $838.6 million as compared to $804.4 million during the same period in 2018, an increase of $34.2 million or 4.3%. In the first quarter of 2018, APUC recorded a one-time acceleration of HLBV income of $55.9 million. Excluding this adjustment, Adjusted EBITDA increased by $90.1 million year over year. The breakdown of Adjusted EBITDA by the Company's main operating segments and a summary of changes are shown below.

Adjusted EBITDA by business units	**Three Months Ended December 31**		**Twelve Months Ended December 31**	
(all dollar amounts in $ millions)	**2019**	**2018**	**2019**	**2018**
Regulated Services Group Operating Profit	**$ 160.5**	$ 135.0	**$ 565.4**	$ 551.6
Renewable Energy Group Operating Profit	**85.9**	78.7	**328.5**	303.6
Administrative Expenses	**(15.2)**	(15.0)	**(56.8)**	(52.7)
Other Income & Expenses	**0.3**	0.2	**1.5**	1.9
Total APUC Adjusted EBITDA	**$ 231.5**	$ 198.9	**$ 838.6**	$ 804.4
Change in Adjusted EBITDA ($)	**$ 32.6**		**$ 34.2**	
Change in Adjusted EBITDA (%)	**16.4%**		**4.3%**	

Change in Adjusted EBITDA	**Three Months Ended December 31, 2019**			
(all dollar amounts in $ millions)	**Regulated Services**	**Renewable Energy**	**Corporate**	**Total**
Prior period balances	**$ 135.0**	**$ 78.7**	**$ (14.8)**	**$ 198.9**
Existing Facilities	17.9	1.6	0.1	19.6
New Facilities and Investments	7.5	5.5	—	13.0
Rate Reviews	0.1	—	—	0.1
Foreign Exchange Impact	—	0.1	—	0.1
Administrative Expenses	—	—	(0.2)	(0.2)
Total change during the period	**$ 25.5**	**$ 7.2**	**$ (0.1)**	**$ 32.6**
Current period balances	**$ 160.5**	**$ 85.9**	**$ (14.9)**	**$ 231.5**

Change in Adjusted EBITDA	**Twelve Months Ended December 31, 2019**			
(all dollar amounts in $ millions)	**Regulated Services**	**Renewable Energy**	**Corporate**	**Total**
Prior period balances	**$ 551.6**	**$ 303.6**	**$ (50.8)**	**$ 804.4**
Existing Facilities	14.9	(49.1) [1]	(0.4)	(34.6)
New Facilities and Investments	7.5	75.3	—	82.8
Rate Reviews	(8.6)	—	—	(8.6)
Foreign Exchange Impact	—	(1.3)	—	(1.3)
Administration Expenses	—	—	(4.1)	(4.1)
Total change during the period	**$ 13.8**	**$ 24.9**	**$ (4.5)**	**$ 34.2**
Current period balances	**$ 565.4**	**$ 328.5**	**$ (55.3)**	**$ 838.6**

[1] Includes a one-time acceleration of HLBV income of $55.9 million recorded in the first quarter of 2018 due to U.S. Tax Reform.

REGULATED SERVICES GROUP

The Regulated Services Group operates rate-regulated utilities that provide distribution services to approximately 804,000 connections in the natural gas, electric, and water and wastewater sectors which is an increase of 36,000 connections as compared to the prior year. On October 1, 2019, with the acquisition of the New Brunswick Gas System, the Regulated Services Group expanded its footprint into Canada and added an additional 12,000 connections. On November 1, 2019, with the acquisition of the St. Lawrence Gas System, the Regulated Services Group added an additional 17,000 connections in New York State. The Regulated Services Group's strategy is to grow its business organically and through business development activities while using prudent acquisition criteria. The Regulated Services Group believes that its business results are maximized by building constructive regulatory and customer relationships, and enhancing connections in the communities in which it operates.

Utility System Type

(all dollar amounts in $ millions)	As at December 31					
	2019			2018		
		Assets	Total Connections[1]		Assets	Total Connections[1]
Electricity	**$**	**2,792.4**	**267,000**	$	2,599.7	266,000
Natural Gas	**$**	**1,377.3**	**369,000**	$	1,088.3	338,000
Water and Wastewater	**$**	**513.6**	**168,000**	$	481.9	164,000
Other	**$**	**71.0**		$	40.2	
Total	**$**	**4,754.3**	**804,000**	$	4,210.1	768,000
Accumulated Deferred Income Taxes Liability		**474.0**		$	438.4	

1 Total Connections represents the sum of all active and vacant connections.

The Regulated Services Group aggregates the performance of its utility operations by utility system type – electricity, natural gas, and water and wastewater systems.

The electric distribution systems are comprised of regulated electrical distribution utility systems and serve approximately 267,000 connections in the States of California, New Hampshire, Missouri, Kansas, Oklahoma, and Arkansas.

The natural gas distribution systems are comprised of regulated natural gas distribution utility systems and serve approximately 369,000 connections located in the States of New Hampshire, Illinois, Iowa, Missouri, Georgia, Massachusetts, New York, and in the Province of New Brunswick.

The water and wastewater distribution systems are comprised of regulated water distribution and wastewater collection utility systems and serve approximately 168,000 connections located in the States of Arkansas, Arizona, California, Illinois, Missouri and Texas. Approximately 4,000 new customers were added through organic growth and from acquisitions of small water utilities compared to the previous year.

2019 Annual Usage Results

Electric Distribution Systems

	Three Months Ended December 31		Twelve Months Ended December 31	
	2019	2018	2019	2018
Average Active Electric Connections For The Period				
Residential	**228,000**	225,900	**227,200**	225,200
Commercial and industrial	**38,100**	37,900	**38,100**	37,800
Total Average Active Electric Connections For The Period	**266,100**	263,800	**265,300**	263,000
Customer Usage (GW-hrs)				
Residential	**599.7**	611.2	**2,488.1**	2,535.1
Commercial and industrial	**932.1**	971.2	**3,944.5**	3,988.9
Total Customer Usage (GW-hrs)	**1,531.8**	1,582.4	**6,432.6**	6,524.0

For the three months ended December 31, 2019, the electric distribution systems' usage totaled 1,531.8 GW-hrs as compared to 1,582.4 GW-hrs for the same period in 2018, a decrease of 50.6 GW-hrs or 3.2%.

For the twelve months ended December 31, 2019, the electric distribution systems' usage totaled 6,432.6 GW-hrs as compared to 6,524.0 GW-hrs for the same period in 2018, a decrease of 91.4 GW-hrs or 1.4%.

Natural Gas Distribution Systems	Three Months Ended December 31		Twelve Months Ended December 31	
	2019	2018	2019	2018
Average Active Natural Gas Connections For The Period				
Residential	**302,700**	288,900	**303,100**	288,700
Commercial and industrial	**35,700**	31,700	**35,600**	31,700
Total Average Active Natural Gas Connections For The Period	**338,400**	320,600	**338,700**	320,400
Customer Usage (MMBTU)				
Residential	**6,341,000**	6,186,000	**20,213,000**	20,065,000
Commercial and industrial	**5,969,000**	4,533,000	**15,676,000**	14,529,000
Total Customer Usage (MMBTU)	**12,310,000**	10,719,000	**35,889,000**	34,594,000

For the three months ended December 31, 2019, usage at the natural gas distribution systems totaled 12,310,000 MMBTU as compared to 10,719,000 MMBTU during the same period in 2018, an increase of 1,591,000 MMBTU, or 14.8%.

For the twelve months ended December 31, 2019, usage at the natural gas distribution systems totaled 35,889,000 MMBTU as compared to 34,594,000 MMBTU during the same period in 2018, an increase of 1,295,000 MMBTU or 3.7%.

Water and Wastewater Distribution Systems	Three Months Ended December 31		Twelve Months Ended December 31	
	2019	2018	2019	2018
Average Active Connections For The Period				
Wastewater connections	**44,400**	43,000	**43,900**	42,200
Water distribution connections	**116,200**	113,200	**115,500**	112,800
Total Average Active Connections For The Period	**160,600**	156,200	**159,400**	155,000
Gallons Provided				
Wastewater treated (millions of gallons)	**592**	606	**2,338**	2,282
Water provided (millions of gallons)	**3,868**	3,655	**15,204**	15,823
Total Gallons Provided	**4,460**	4,261	**17,542**	18,105

During the three months ended December 31, 2019, the water and wastewater distribution systems provided approximately 3,868 million gallons of water to its customers and treated approximately 592 million gallons of wastewater as compared to 3,655 million gallons of water provided and 606 million gallons of wastewater treated during the same period in 2018.

During the twelve months ended December 31, 2019, the water and wastewater distribution systems provided approximately 15,204 million gallons of water to its customers and treated approximately 2,338 million gallons of wastewater as compared to 15,823 million gallons of water and 2,282 million gallons of wastewater during the same period in 2018.

2019 Regulated Services Group Operating Results

	Three Months Ended December 31		Twelve Months Ended December 31	
	2019	**2018**	**2019**	**2018**
Revenue				
Utility electricity sales and distribution	**$ 181.9**	$ 193.2	**$ 784.4**	$ 831.2
Less: cost of sales – electricity	**(59.2)**	(63.4)	**(247.4)**	(265.1)
Net Utility Sales - electricity[1]	**122.7**	129.8	**537.0**	566.1
Utility natural gas sales and distribution	**132.3**	117.5	**402.6**	396.6
Less: cost of sales – natural gas	**(58.9)**	(59.0)	**(170.5)**	(183.0)
Net Utility Sales - natural gas[1]	**73.4**	58.5	**232.1**	213.6
Utility water distribution & wastewater treatment sales and distribution	**32.0**	30.4	**130.5**	128.4
Less: cost of sales – water	**(2.2)**	(2.1)	**(8.1)**	(8.8)
Net Utility Sales - water distribution & wastewater treatment[1]	**29.8**	28.3	**122.4**	119.6
Gas transportation	**11.4**	10.4	**35.1**	33.4
Other revenue	**7.7**	4.9	**14.3**	11.6
Net Utility Sales[1]	**245.0**	231.9	**940.9**	944.3
Operating expenses	**(96.0)**	(99.0)	**(396.6)**	(401.5)
Other income	**10.2**	1.5	**15.3**	5.6
HLBV[2]	**1.3**	0.6	**5.8**	3.2
Divisional Operating Profit[1,3]	**$ 160.5**	$ 135.0	**$ 565.4**	$ 551.6

1 See *Non-GAAP Financial Measures*.

2 HLBV income represents the value of net tax attributes monetized by the Regulated Services Group in the period at the Luning Solar Facility.

3 Certain prior year items have been reclassified to conform with current year presentation.

2019 Fourth Quarter Operating Results

For the three months ended December 31, 2019, the Regulated Services Group reported an operating profit (excluding corporate administration expenses) of $160.5 million as compared to $135.0 million for the comparable period in the prior year.

Highlights of the changes are summarized in the following table:

(all dollar amounts in $ millions)		Three Months Ended December 31
Prior Period Operating Profit	**$**	**135.0**
Existing Facilities		
Electricity: Increase is primarily due to operating cost savings at the Granite State Electric System, partially offset by lower consumption due to fewer heating degree days at the Empire Electric System.		1.2
Gas: Increase is primarily due to lower operating costs at the EnergyNorth Gas System as well as additional Gas System Enhancement Program ("GSEP") recoveries at the New England Gas System.		2.5
Water: Increase is due to higher revenues from organic growth in connections as well as operating cost savings at the Arkansas and Park Water Systems.		3.1
Increase in revenue from utility services provided to Ft. Benning and fees earned from the San Antonio Water System investment.		7.8
Increase in allowance for funds used during construction ("AFUDC") due to higher construction work in progress.		3.3
		17.9
New Facilities		
Gas: Acquisitions of New Brunswick Gas (October 2019) and St. Lawrence Gas (November 2019).		7.5
		7.5
Rate Reviews		
Electricity: Implementation of new rates at the Granite State Electric System.		0.3
Water: Implementation of lower rates at the Park Water System due to U.S. Tax Reform, partially offset by higher rates at the Tall Timbers Water System, net of U.S. Tax Reform impact.		(0.2)
		0.1
Current Period Divisional Operating Profit[1]	**$**	**160.5**

1 See *Non-GAAP Financial Measures*.

2019 Annual Operating Results

For the twelve months ended December 31, 2019, the Regulated Services Group reported an operating profit (excluding corporate administration expenses) of $565.4 million as compared to $551.6 million for the comparable period in the prior year.

Highlights of the changes are summarized in the following table:

(all dollar amounts in $ millions)		Twelve Months Ended December 31
Prior Period Operating Profit	**$**	**551.6**
Existing Facilities		
Electricity: Decrease is primarily due to less extreme weather conditions as compared to the prior year resulting in lower consumption at the Empire Electric System as well as higher operating costs at the CalPeco Electric System, partially offset by operating cost savings at the Granite State and Empire Electric Systems.		(8.8)
Gas: Increase is primarily due to operating cost savings at the EnergyNorth, New England and Empire Gas Systems as well as additional GSEP recoveries at the New England Gas System.		7.5
Water: Increase is primarily due to higher revenues resulting from organic growth and several small water utility acquisitions throughout the year in the Arizona, Texas and Park Water Systems as well as operating cost savings at the Park Water and Arkansas Water Systems.		3.9
Increase in revenue from utility services provided to Ft. Benning and fees earned from the San Antonio Water System investment.		8.1
Other: Increase in AFUDC due to higher construction work in progress.		4.2
		14.9
New Facilities		
Gas: Acquisitions of New Brunswick Gas (October 2019) and St. Lawrence Gas (November 2019).		7.5
		7.5
Rate Reviews		
Electricity: Implementation of lower rates at the Empire Electric System due to U.S. Tax Reform.		(13.0)
Gas: Implementation of new rates, net of U.S. Tax Reform impact, primarily at the Midstates and EnergyNorth Gas Systems, partially offset by lower rates at the Empire Gas System due to U.S. Tax Reform.		5.0
Water: Implementation of lower rates at the Park Water System due to U.S. Tax Reform, partially offset by new rates, net of U.S. Tax Reform impact, at the Litchfield Park Water System.		(0.6)
		(8.6)
Current Period Divisional Operating Profit[1]	**$**	**565.4**

1 See *Non-GAAP Financial Measures*.

Regulatory Proceedings

The following table summarizes the major regulatory proceedings currently underway within the Regulated Services Group:

Utility	State/Province	Regulatory Proceeding Type	Rate Request (millions)	Current Status
Completed Rate Reviews				
Peach State Gas System	Georgia	GRAM	$2.7	On January 31, 2019, an Order was issued approving an increase in revenue of $2.4 million for rates effective February 1, 2019.
New England Gas System	Massachusetts	GSEP	$3.8	On April 30, 2019, an Order was issued approving an increase in revenue of $2.4 million for rates effective May 1, 2019.
CalPeco Electric System	California	Catastrophic Events Memorandum Account	$3.8	On June 13, 2019, an Order was issued authorizing a one-time recovery of $3.5 million in revenue associated with its 2017 storm-related costs, effective in rates January 1, 2020.
Empire Electric (Kansas System)	Kansas	GRC	$2.5	On July 30, 2019, an Order was issued approving base rates to remain unchanged and a transmission delivery charge rider approving an annual increase of $2.5 million. The Order became effective August 1, 2019.
Empire Electric (Oklahoma System)	Oklahoma	GRC	$2.3	On October 9, 2019, an Order was issued approving an annual base rate increase of $1.4 million effective October 1, 2019.
Various	Various	GRC	$2.4	Approval of $0.2 million in rate decrease across water, wastewater, and natural gas utilities.
Pending Rate Reviews				
Empire Electric (Missouri System)	Missouri	GRC	$26.5	On August 14, 2019, filed an application for an annual increase in the revenue requirement of approximately $26.5 million.
Granite State Electric System	New Hampshire	GRC	$9.0	On April 30, 2019, filed a rate review requesting increases of $2.1 million for temporary rates effective July 1, 2019, $5.7 million for permanent rates effective May 1, 2020, and a step increase of $2.3 million effective May 1, 2020. On June 28, 2019, a temporary rate increase of $2.1 million was approved by the New Hampshire Public Utilities Commission ("NHPUC"). On November 22, 2019, Granite State filed an update requesting an increase of $6.7 million for permanent rates effective May 1, 2020.
Energy North Gas System	New Hampshire	GRC	$13.8	On November 27, 2019, filed a rate application requesting increases of $7.9 million for temporary rates effective February 1, 2020, $10.8 million for permanent rates effective November 1, 2020, and a step increase of $3.0 million effective November 1, 2020. On January 10, 2020, the NHPUC heard arguments on whether it should use its discretion to not investigate this rate request within a two-year window of time from its prior review. A decision is pending.
New England Gas System	Massachusetts	GSEP	$3.2	On October 31, 2019, filed the 2020 GSEP application requesting an incremental increase in revenue of $3.2 million effective May 1, 2020.
CalPeco Electric System	California	GRC	$14.9	A rate review is currently underway requesting a rate increase of $14.9 million over three years ($6.9 million for 2019, $4.1 million for 2020, and $3.9 million for 2021).
Various	Various	Various	$1.9	Other pending rate review requests across two water utilities and one wastewater utility.

2019 Electricity Generation Performance

(Performance in GW-hrs sold)	Long Term Average Resource	Three Months Ended December 31 2019	Three Months Ended December 31 2018	Long Term Average Resource	Twelve Months Ended December 31 2019	Twelve Months Ended December 31 2018
Hydro Facilities:						
Maritime Region	**37.6**	**35.8**	31.4	**148.2**	**132.7**	107.5
Quebec Region	**72.6**	**72.7**	73.6	**273.3**	**270.8**	263.7
Ontario Region	**26.2**	**22.2**	31.3	**120.4**	**103.4**	106.5
Western Region	**12.6**	**13.3**	11.2	**65.0**	**65.5**	59.8
	149.0	**144.0**	147.5	**606.9**	**572.4**	537.5
Wind Facilities:						
St. Damase	**22.7**	**20.5**	22.2	**76.9**	**76.7**	78.8
St. Leon	**121.4**	**112.4**	101.4	**430.2**	**404.0**	394.8
Red Lily[1]	**24.1**	**23.4**	20.0	**88.5**	**81.8**	81.3
Morse	**30.5**	**25.9**	26.2	**108.8**	**96.4**	96.8
Amherst[2]	**67.9**	**67.0**	58.7	**229.8**	**223.4**	105.7
Sandy Ridge	**43.6**	**31.9**	43.8	**158.3**	**126.5**	152.2
Minonk	**189.8**	**193.7**	173.8	**673.7**	**654.6**	611.3
Senate	**140.0**	**131.1**	125.2	**520.4**	**506.0**	484.9
Shady Oaks	**100.5**	**97.7**	91.5	**355.6**	**345.8**	326.6
Odell	**238.0**	**224.9**	199.9	**831.8**	**748.1**	759.4
Deerfield	**167.9**	**163.9**	153.8	**546.0**	**522.6**	531.2
	1,146.4	**1,092.4**	1,016.5	**4,020.0**	**3,785.9**	3,623.0
Solar Facilities:						
Cornwall	**2.2**	**1.8**	1.8	**14.7**	**15.0**	14.5
Bakersfield	**13.0**	**12.2**	9.5	**77.2**	**68.6**	70.0
Great Bay Solar[3]	**25.7**	**24.2**	26.4	**138.5**	**134.2**	110.6
	40.9	**38.2**	37.7	**230.4**	**217.8**	195.1
Renewable Energy Performance	**1,336.3**	**1,274.6**	1,201.7	**4,857.3**	**4,576.1**	4,355.6
Thermal Facilities:						
Windsor Locks	**N/A[4]**	**28.0**	46.1	**N/A[4]**	**115.3**	154.7
Sanger	**N/A[4]**	**17.8**	11.3	**N/A[4]**	**57.6**	146.4
		45.8	57.4		**172.9**	301.1
Total Performance		**1,320.4**	1,259.1		**4,749.0**	4,656.7

1 APUC owns a 75% equity interest in the Red Lily Wind Facility but accounts for the facility using the equity method. The production figures represent full energy produced by the facility.

2 APUC owns a majority interest in the Amherst Island Wind Facility. The production figures represent full energy produced by the facility. The Amherst Island Wind Facility achieved COD on June 15, 2018 in accordance with the terms of the Power Purchase Agreement ("PPA"), however, the facility was partially operational prior to that date. The twelve months ended December 31, 2018 production data includes all energy produced during the year.

3 The Great Bay Solar Facility achieved COD on March 29, 2018 in accordance with the terms of the PPA, however, the facility was partially operational prior to that date. The twelve months ended December 31, 2018 production data includes all energy produced during the year.

4 Natural gas fired co-generation facility.

2019 Fourth Quarter Renewable Energy Group Performance

For the three months ended December 31, 2019, the Renewable Energy Group generated 1,320.4 GW-hrs of electricity as compared to 1,259.1 GW-hrs during the same period of 2018.

For the three months ended December 31, 2019, the hydro facilities generated 144.0 GW-hrs of electricity as compared to 147.5 GW-hrs produced in the same period in 2018, a decrease of 2.4%. Electricity generated represented 96.6% of long-term average resources ("LTAR") as compared to 99.0% during the same period in 2018. During the quarter, all regions except the Maritime Region were above their respective LTAR.

For the three months ended December 31, 2019, the wind facilities produced 1,092.4 GW-hrs of electricity as compared to 1,016.5 GW-hrs produced in the same period in 2018, an increase of 7.5%. During the three months ended December 31, 2019, the wind facilities generated electricity equal to 95.3% of LTAR as compared to 88.7% during the same period in 2018.

For the three months ended December 31, 2019, the solar facilities generated 38.2 GW-hrs of electricity as compared to 37.7 GW-hrs of electricity in the same period in 2018, an increase of 1.3%. The solar facilities generated electricity equal to 93.4% of LTAR as compared to 92.2% in the same period in 2018.

For the three months ended December 31, 2019, the thermal facilities generated 45.8 GW-hrs of electricity as compared to 57.4 GW-hrs of electricity during the same period in 2018. During the same period, the Windsor Locks Thermal Facility generated 153.7 billion lbs of steam as compared to 145.7 billion lbs of steam during the same period in 2018.

2019 Annual Renewable Energy Group Performance

For the twelve months ended December 31, 2019, the Renewable Energy Group generated 4,749.0 GW-hrs of electricity as compared to 4,656.7 GW-hrs during the same period of 2018.

For the twelve months ended December 31, 2019, the hydro facilities generated 572.4 GW-hrs of electricity as compared to 537.5 GW-hrs produced in the same period in 2018, an increase of 6.5%. Electricity generated represented 94.3% of LTAR as compared to 88.6% during the same period in 2018.

For the twelve months ended December 31, 2019, the wind facilities produced 3,785.9 GW-hrs of electricity as compared to 3,623.0 GW-hrs produced in the same period in 2018, an increase of 4.5%. The increase in production was primarily due to incremental electricity generated at the Amherst Wind Facility which achieved COD on June 15, 2018. During the twelve months ended December 31, 2019, the wind facilities generated electricity equal to 94.2% of LTAR as compared to 92.7% during the same period in 2018.

For the twelve months ended December 31, 2019, the solar facilities generated 217.8 GW-hrs of electricity as compared to 195.1 GW-hrs of electricity produced in the same period in 2018, an increase of 11.6%. The increase in production is primarily due to the addition of the Great Bay Solar Facility which achieved full COD on March 29, 2018. The solar facilities generated electricity equal to 94.5% of LTAR as compared to 94.0% in the same period in 2018.

For the twelve months ended December 31, 2019, the thermal facilities generated 172.9 GW-hrs of electricity as compared to 301.1 GW-hrs of electricity during the same period in 2018. During the same period, the Windsor Locks Thermal Facility generated 555.4 billion lbs of steam as compared to 566.9 billion lbs of steam during the same period in 2018.

2019 Renewable Energy Group Operating Results

(all dollar amounts in $ millions)	Three Months Ended December 31		Twelve Months Ended December 31	
	2019	**2018**	**2019**	**2018**
Revenue[1]				
Hydro	**$ 10.4**	$ 11.7	**$ 41.7**	$ 42.6
Wind	**49.4**	37.7	**153.3**	133.5
Solar	**2.8**	2.8	**18.6**	17.2
Thermal	**8.1**	10.2	**32.9**	42.1
Total Revenue	**$ 70.7**	$ 62.4	**$ 246.5**	$ 235.4
Less:				
Cost of Sales - Energy[2]	**(0.9)**	(1.4)	**(4.3)**	(5.5)
Cost of Sales - Thermal	**(3.2)**	(5.1)	**(13.0)**	(21.7)
Realized gain/(loss) on hedges[3]	**—**	0.1	**(0.2)**	0.1
Net Energy Sales[8]	**$ 66.6**	$ 56.0	**$ 229.0**	$ 208.3
Renewable Energy Credits[4]	**2.8**	2.7	**10.1**	11.0
Other Revenue	**0.8**	0.4	**1.4**	0.9
Total Net Revenue	**$ 70.2**	$ 59.1	**$ 240.5**	$ 220.2
Expenses & Other Income				
Operating expenses	**(19.2)**	(13.2)	**(75.2)**	(71.0)
Dividend, interest, equity and other income[5]	**20.2**	18.3	**104.0**	45.7
HLBV income[8]	**14.7**	14.5	**59.2**	108.7
Divisional Operating Profit[6,7]	**$ 85.9**	$ 78.7	**$ 328.5**	$ 303.6

1 Many of the Renewable Energy Group's PPAs include annual rate increases however, a change to the weighted average production levels resulting from higher average production from facilities that earn lower energy rates can result in a lower weighted average energy rate earned by the division as compared to the same period in the prior year.

2 Cost of Sales - Energy consists of energy purchases in the Maritime Region to manage the energy sales from the Tinker Hydro Facility which is sold to retail and industrial customers under multi-year contracts.

3 See *Note 24(b)(iv)* in the annual audited consolidated financial statements.

4 Qualifying renewable energy projects receive RECs for the generation and delivery of renewable energy to the power grid. The energy credit certificates represent proof that 1 MW-hr of electricity was generated from an eligible energy source.

5 Includes dividends received from Atlantica and related parties (see *Note 8 and 16* in the annual audited consolidated financial statements).

6 Certain prior year items have been reclassified to conform to current year presentation.

7 See *Non-GAAP Financial Measures*.

8 HLBV Income and Production Tax Credits

HLBV income represents the value of net tax attributes earned by the Renewable Energy Group in the period primarily from electricity generated by certain of its U.S. wind and U.S. solar generation facilities.

Production Tax Credits ("PTCs") are earned as wind energy is generated based on a dollar per kW-hr rate prescribed in applicable federal and state statutes. For the three and twelve months ended December 31, 2019, the Renewable Energy Group's eligible facilities generated 745.5 and 2,557.8 GW-hrs representing approximately $18.6 million and $63.9 million in PTCs earned as compared to 696.5 and 2,539.0 GW-hrs representing $16.7 million and $60.9 million in PTCs earned during the same period in 2018. The majority of the PTCs have been allocated to tax equity investors to monetize the value to APUC of the PTCs and other tax attributes which are being recognized as HLBV income.

2019 Fourth Quarter Operating Results

For the three months ended December 31, 2019, the Renewable Energy Group's facilities generated $85.9 million of operating profit as compared to $78.7 million during the same period in 2018, which represents an increase of $7.2 million or 9.1%, excluding corporate administration expenses.

Highlights of the changes are summarized in the following table:

(all dollar amounts in $ millions)	Three Months Ended December 31	
Prior Period Operating Profit	**$**	**78.7**
Existing Facilities		
Hydro: Decrease is primarily due to lower production in the Ontario and Quebec Regions, partially offset by additional REC revenue and lower operating expenses.		(0.2)
Wind Canada: Increase is primarily due to higher production at the St. Leon Wind Facility, partially offset by higher operating expenses.		0.9
Wind U.S.: Increase is primarily due to higher overall production as well as lower operating expenses.		2.4
Solar Canada		—
Solar U.S.: Decrease due to lower production at the Great Bay Solar Facility partially offset by favorable REC pricing, higher HLBV income and higher production at the Bakersfield Solar Facility.		(0.2)
Thermal: Increase is primarily due to lower cost of fuel at the Sanger Thermal Facility as well additional REC revenue, partially offset by lower production at the Windsor Locks Thermal Facility.		0.4
Other: Decrease is due to higher expenses related to early stage development projects.		(1.7)
		1.6
New Facilities and Investments		
Wind Canada: The Amherst Island Wind Facility was previously accounted for as an equity investment.		4.5
Atlantica & AAGES: Dividends from Atlantica[1], net of AAGES equity loss.		1.0
		5.5
Foreign Exchange		**0.1**
Current Period Divisional Operating Profit[2]	**$**	**85.9**

1 Includes dividends received from Atlantica and related parties (see *Note 8 and 16* in the annual audited consolidated financial statements).

2 See *Non-GAAP Financial Measures*.

2019 Annual Operating Results

For the twelve months ended December 31, 2019, the Renewable Energy Group's facilities generated $328.5 million of operating profit as compared to $303.6 million during the same period in 2018, which represents an increase of $24.9 million or 8.2%, excluding corporate administration expenses.

Highlights of the changes are summarized in the following table:

(all dollar amounts in $ millions)	Twelve Months Ended December 31	
Prior Period Operating Profit	**$**	**303.6**
Existing Facilities		
Hydro: Increase is primarily due to higher production and additional REC sales, partially offset by higher operating expenses.		0.8
Wind Canada: Increase is primarily due to annual rate increases and higher production at the St. Leon Wind Facility, partially offset by higher operating costs.		1.6
Wind U.S.: Decrease is primarily due to HLBV income acceleration ($54.9 million) resulting from U.S. Tax Reform recognized in the prior year, lower market pricing at the Senate Wind Facility and lower REC rates at the Minonk Wind Facility, partially offset by higher overall production.		(54.2)
Solar Canada: Decrease is primarily due to higher operating expenses offset by higher production.		(0.1)
Solar U.S.: Decrease is primarily due to HLBV income acceleration ($1.0 million) resulting from U.S. Tax Reform that was recognized in the prior year.		(1.0)
Thermal: Increase is primarily due to lower operating costs, lower cost of fuel and higher REC revenue, partially offset by lower overall production.		0.7
Other: Increase is due to lower expenses related to early stage development projects.		3.1
		(49.1)
New Facilities and Investments		
Wind Canada: Amherst Island Wind Facility achieved COD in June 2018.		15.9
Solar U.S.: Great Bay Solar Facility achieved full COD in March 2018.		6.4
Atlantica and AAGES: Dividends from Atlantica[1] net of AAGES equity loss.		53.0
		75.3
Foreign Exchange		**(1.3)**
Current Period Divisional Operating Profit[2]	**$**	**328.5**

1 Includes dividends received from Atlantica and related parties (see *Note 8 and 16* in the annual audited consolidated financial statements).

2 See *Non-GAAP Financial Measures*.

APUC: CORPORATE AND OTHER EXPENSES

	Three Months Ended December 31		Twelve Months Ended December 31	
(all dollar amounts in $ millions)	**2019**	**2018**	**2019**	**2018**
Corporate and other expenses:				
Administrative expenses	**$ 15.2**	$ 15.0	**$ 56.8**	$ 52.7
Loss (gain) on foreign exchange	**3.1**	0.7	**3.1**	(0.1)
Interest expense	**47.4**	40.3	**181.5**	152.1
Depreciation and amortization	**77.7**	63.8	**284.3**	260.8
Change in value of investments carried at fair value	**(98.1)**	46.0	**(278.1)**	138.0
Interest, dividend, equity, and other (income) loss[1]	**(0.4)**	(0.4)	**(1.6)**	(1.8)
Pension and post-employment non-service costs	**8.4**	3.4	**17.3**	5.0
Other losses	**6.2**	2.3	**15.1**	2.7
Acquisition-related costs, net	**6.4**	(8.9)	**11.6**	0.7
Loss (gain) on derivative financial instruments	**(0.5)**	(0.3)	**(16.1)**	0.6
Income tax expense	**12.5**	2.8	**70.1**	53.4

[1] Excludes income directly pertaining to the Regulated Services and Renewable Energy Groups (disclosed in the relevant sections).

2019 Fourth Quarter Corporate and Other Expenses

During the three months ended December 31, 2019, administrative expenses totaled $15.2 million as compared to $15.0 million in the same period in 2018.

For the three months ended December 31, 2019, interest expense totaled $47.4 million as compared to $40.3 million in the same period in 2018. The increase was primarily due to the issuance of senior unsecured debentures and the Notes in January and May of 2019 respectively.

For the three months ended December 31, 2019, depreciation expense totaled $77.7 million as compared to $63.8 million in the same period in 2018. The increase is primarily due to higher overall property, plant and equipment.

For the three months ended December 31, 2019, change in investments carried at fair value totaled a gain of $98.1 million as compared to a loss of $46 million in 2018. The Company records certain of its investments, including Atlantica, using the fair value method and accordingly any change in the fair value of the investment is recorded in the Statement of Operations (see *Note 8* in the annual audited consolidated financial statements).

For the three months ended December 31, 2019, pension and post-employment non-service costs totaled $8.4 million as compared to $3.4 million in 2018. The increase in 2019 was primarily due to the actual return on plan assets in 2018 being lower than anticipated, resulting in lower expected return on assets in 2019 and higher amortization cost of actuarial losses.

For the three months ended December 31, 2019, other losses were $6.2 million as compared to $2.3 million in the same period in 2018. The loss in 2019 was primarily related to condemnation costs for Liberty Utilities (Apple Valley Ranchos Water) Corp. as well as write-downs of some regulatory assets at the Empire Electric and Energy North Natural Gas Systems. The loss in 2018 primarily related to the write down of notes receivables and costs from condemnation proceedings.

For the three months ended December 31, 2019, acquisition related costs totaled $6.4 million as compared to a cost recovery of $8.9 million in 2018. The expense in 2019 was primarily related to the investment in Atlantica, the pending acquisition of New York American Water and the acquisitions of New Brunswick Gas and St. Lawrence Gas. The recovery in 2018 was primarily due to a settlement related to the Shady Oaks Wind Facility acquisition.

For the three months ended December 31, 2019, gain on derivative financial instruments totaled $0.5 million as compared to $0.3 million in the same period in 2018. The gains in 2019 were primarily driven by mark-to-market gains on energy derivatives.

For the three months ended December 31, 2019, an income tax expense of $12.5 million was recorded as compared to an income tax expense of $2.8 million during the same period in 2018. In the three months ended December 31, 2019, increases to income tax expense are primarily due to the change in fair value associated with the investment in Atlantica partially offset by lower income subject to tax and investment tax credits earned. In the three months ended December 31, 2018, income tax expense was impacted by a one-time U.S. Tax Reform related benefit.

2019 Annual Corporate and Other Expenses

During the twelve months ended December 31, 2019, administrative expenses totaled $56.8 million as compared to $52.7 million in the same period in 2018. The increase primarily relates to additional costs incurred to administer APUC's operations as a result of the Company's growth.

For the twelve months ended December 31, 2019, interest expense totaled $181.5 million as compared to $152.1 million in the same period in 2018. The increase was primarily due to the issuance of subordinated notes in October 2018 and May 2019 and higher average long-term debt balances.

For the twelve months ended December 31, 2019, depreciation expense totaled $284.3 million as compared to $260.8 million in the same period in 2018. The increase is primarily due to higher overall property, plant and equipment.

For the twelve months ended December 31, 2019, change in investments carried at fair value totaled a gain of $278.1 million as compared to a loss of $138.0 million in the same period in 2018. The Company records certain of its investments, including Atlantica, using the fair value method and accordingly any change in the fair value of the investment is recorded in the Statement of Operations (see *Note 8* in the annual audited consolidated financial statements).

For the twelve months ended December 31, 2019, pension and post-employment non-service costs totaled $17.3 million as compared to $5.0 million in the same period in 2018. The increase in 2019 was primarily due to the actual return on plan assets in 2018 being lower than expected, resulting in lower expected return on assets in 2019 and higher amortization cost of actuarial losses.

For the twelve months ended December 31, 2019, other losses were $15.1 million as compared to $2.7 million in the same period in 2018. The loss in 2019 is primarily related to condemnation costs for Liberty Utilities (Apple Valley Ranchos Water) Corp. as well as write-downs of regulatory assets at the Empire Electric, Energy North Natural Gas and Granite State Electric Systems. The loss in 2018 was primarily related to the write-down of notes receivables and costs from condemnation proceedings.

For the twelve months ended December 31, 2019, acquisition-related costs totaled $11.6 million as compared to $0.7 million in the same period in 2018. The expense in 2019 was primarily related to the investment in Atlantica, the pending acquisition of New York American Water and the acquisitions of New Brunswick Gas and St. Lawrence Gas. The costs in 2018 primarily related to the investment in Atlantica, partially offset by a settlement related to the Shady Oaks Wind Facility acquisition.

For the twelve months ended December 31, 2019, the gain on derivative financial instruments totaled $16.1 million as compared to a loss of $0.6 million in the same period in 2018. The gain in 2019 was primarily related to the discontinuation of hedge accounting on energy derivatives as a result of the sale of an interest in the Sugar Creek Wind Project to AAGES (see *Note 24(b)(ii)* in the annual audited consolidated financial statements).

An income tax expense of $70.1 million was recorded in the twelve months ended December 31, 2019 as compared to an income tax expense of $53.4 million during the same period in 2018. In 2019, increases to income tax expense are primarily due to the change in fair value associated with the investment in Atlantica partially offset by lower income subject to tax and investment tax credits earned. In 2018, income tax expense was impacted by a one-time U.S. Tax Reform related benefit offset by higher HLBV earnings in 2018 also due to U.S. Tax Reform.

NON-GAAP FINANCIAL MEASURES

Reconciliation of Adjusted EBITDA to Net Earnings

The following table is derived from and should be read in conjunction with the consolidated statement of operations. This supplementary disclosure is intended to more fully explain disclosures related to Adjusted EBITDA and provides additional information related to the operating performance of APUC. Investors are cautioned that this measure should not be construed as an alternative to U.S. GAAP consolidated net earnings.

	Three Months Ended December 31		Twelve Months Ended December 31	
(all dollar amounts in $ millions)	**2019**	**2018**	**2019**	**2018**
Net earnings attributable to shareholders	**$ 172.1**	$ 44.0	**$ 530.9**	$ 185.0
Add (deduct):				
Net earnings attributable to the non-controlling interest, exclusive of HLBV[1]	**(3.7)**	3.4	**19.1**	4.8
Income tax expense	**12.5**	2.8	**70.1**	53.4
Interest expense on long-term debt and others	**47.4**	40.3	**181.5**	152.1
Other losses	**6.2**	2.3	**15.1**	2.7
Acquisition-related costs	**6.4**	(8.9)	**11.6**	0.7
Pension and post-employment non-service costs	**8.4**	3.4	**17.3**	5.0
Change in value of investments carried at fair value[2]	**(98.1)**	46.0	**(278.1)**	138.0
Costs related to tax equity financing	**—**	1.3	**—**	1.3
Loss (gain) on derivative financial instruments	**(0.5)**	(0.3)	**(16.1)**	0.6
Realized (loss) gain on energy derivative contracts	**—**	0.1	**(0.2)**	0.1
Loss (gain) on foreign exchange	**3.1**	0.7	**3.1**	(0.1)
Depreciation and amortization	**77.7**	63.8	**284.3**	260.8
Adjusted EBITDA	**$ 231.5**	$ 198.9	**$ 838.6**	$ 804.4

1 HLBV represents the value of net tax attributes earned during the period primarily from electricity generated by certain U.S. wind power and U.S. solar generation facilities. HLBV earned in the three and twelve months ended December 31, 2019 amounted to $16.0 million and $65.0 million as compared to $13.8 million and $110.7 million during the same period in 2018. In the first quarter of 2018 a one-time acceleration of HLBV income in the amount of $55.9 million was recorded as a result of U.S. Tax Reform. Excluding the one-time acceleration of HLBV due to U.S. Tax Reform, Adjusted EBITDA increased by $90.1 million year over year.

2 See *Note 8* in the annual audited consolidated financial statements

Reconciliation of Adjusted Net Earnings to Net Earnings

The following table is derived from and should be read in conjunction with the consolidated statement of operations. This supplementary disclosure is intended to more fully explain disclosures related to Adjusted Net Earnings and provides additional information related to the operating performance of APUC. Investors are cautioned that this measure should not be construed as an alternative to consolidated net earnings in accordance with U.S. GAAP.

The following table shows the reconciliation of net earnings to Adjusted Net Earnings exclusive of these items:

	Three Months Ended December 31		Twelve Months Ended December 31	
(all dollar amounts in $ millions except per share information)	**2019**	**2018**	**2019**	**2018**
Net earnings attributable to shareholders	**$ 172.1**	$ 44.0	**$ 530.9**	$ 185.0
Add (deduct):				
Loss (gain) on derivative financial instruments[1]	**(0.5)**	(0.3)	**(0.3)**	0.6
Realized (loss) gain on energy derivative contracts	**—**	0.1	**(0.2)**	0.1
Other losses	**6.1**	1.9	**15.1**	0.8
Loss (gain) on foreign exchange	**3.0**	0.7	**3.1**	(0.1)
Acquisition-related costs	**6.4**	(8.9)	**11.6**	0.7
Change in value of investments carried at fair value[3]	**(98.1)**	46.0	**(278.1)**	138.0
Costs related to tax equity financing	**—**	1.3	**—**	1.3
Other non-recurring adjustments	**2.2**	—	**2.2**	—
U.S. Tax Reform and related deferred tax adjustments[2]	**—**	(18.4)	**—**	(18.4)
Adjustment for taxes related to above	**12.4**	4.1	**37.0**	4.2
Adjusted Net Earnings	**$ 103.6**	$ 70.5	**$ 321.3**	$ 312.2
Adjusted Net Earnings per share	**$ 0.20**	$ 0.14	**$ 0.63**	$ 0.66

1 Excludes the gain related to the discontinuation of hedge accounting on an energy hedge put in place early in the development of the Sugar Creek Wind Project (See *Note 24(b)(ii)* in the annual audited consolidated financial statements).

2 Represents the non-cash accounting adjustment related to the revaluation of U.S. deferred income tax assets and liabilities as a result of implementation of the effects of U.S. Tax Reform.

3 See *Note 8* in the annual audited consolidated financial statements

For the three months ended December 31, 2019, Adjusted Net Earnings totaled $103.6 million as compared to Adjusted Net Earnings of $70.5 million for the same period in 2018, an increase of $33.1 million.

For the twelve months ended December 31, 2019, Adjusted Net Earnings totaled $321.3 million as compared to Adjusted Net Earnings of $312.2 million for the same period in 2018, an increase of $9.1 million. In the first quarter of 2018 a one-time acceleration of HLBV income in the amount of $55.9 million was recorded as a result of U.S. Tax Reform.

Reconciliation of Adjusted Funds from Operations to Cash Flows from Operating Activities

The following table is derived from and should be read in conjunction with the consolidated statement of operations and consolidated statement of cash flows. This supplementary disclosure is intended to more fully explain disclosures related to Adjusted Funds from Operations and provides additional information related to the operating performance of APUC. Investors are cautioned that this measure should not be construed as an alternative to funds from operations in accordance with U.S GAAP.

The following table shows the reconciliation of funds from operations to Adjusted Funds from Operations exclusive of these items:

	Three Months Ended December 31		Twelve Months Ended December 31	
(all dollar amounts in $ millions)	**2019**	2018	**2019**	2018
Cash flows from operating activities	**$ 167.5**	$ 168.6	**$ 611.3**	$ 530.4
Add (deduct):				
Changes in non-cash operating items	**(29.8)**	(27.3)	**(60.3)**	8.1
Production based cash contributions from non-controlling interests	**—**	—	**3.6**	13.9
Acquisition-related costs	**6.4**	(8.8)	**11.6**	0.7
Reimbursement of operating expenses incurred on joint venture	**—**	—	**—**	1.0
Adjusted Funds from Operations	**$ 144.1**	$ 132.5	**$ 566.2**	$ 554.1

For the three months ended December 31, 2019, Adjusted Funds from Operations totaled $144.1 million as compared to Adjusted Funds from Operations of $132.5 million for the same period in 2018, an increase of $11.6 million.

For the twelve months ended December 31, 2019, Adjusted Funds from Operations totaled $566.2 million as compared to Adjusted Funds from Operations of $554.1 million for the same period in 2018, an increase of $12.1 million. The increase is primarily due to an increase in earnings from operating facilities and an increase in income from long-term investments.

CORPORATE DEVELOPMENT ACTIVITIES

The Company undertakes development activities working within a global reach to identify, develop, and construct both regulated and non-regulated renewable power generating facilities, power transmission lines, water infrastructure assets, and other complementary infrastructure projects as well as to invest in local utility electric, natural gas and water distribution systems.

The Company has identified an approximately $9.2 billion development pipeline consisting of approximately $6.7 billion of investments in its Regulated Services Group and approximately $2.5 billion of investments in its Renewable Energy Group through the end of 2024.

APUC pursues investment opportunities with an objective to maintain its business mix in approximately the same proportion as currently exists between its Regulated Services Group and Renewable Energy Group and within credit metrics expected to maintain its current credit ratings. The business mix target may from time to time require APUC to grow its Regulated Services Group or implement other strategies in order to pursue investment opportunities within its Renewable Energy Group.

Development of Regulated Services Assets

The approximately five-year $6.7 billion Regulated Services Group pipeline consists of investments of $2.7 billion in organic rate base capital expenditures, $1.1 billion in capital expenditures related to improving the quality of choice and efficiency of service provided to our customers, $1.1 billion on pending acquisitions, and $1.9 billion in initiatives focused on transition to green energy ("Greening the Fleet").

Organic rate base capital expenditures are primarily related to the maintenance and expansion of existing rate base assets, including: the construction of transmission and distribution main replacements, work on new and existing substation assets and initiatives relating to the safety and reliability of the electric and gas systems.

Capital expenditures related to improving quality and efficiency of service to our customers include the implementation of new customer information systems, advanced metering systems and behind the meter solutions.

Pending acquisitions include BELCO for approximately $0.5 billion, which is expected to close later in 2020, and New York American Water for approximately $0.6 billion, which is expected to close sometime in 2021.

The $1.9 billion Greening the Fleet initiatives consist primarily of a $1.1 billion Mid-West Wind Development project (described below) and $0.8 billion in other initiatives related to the transition to renewable energy generation at our existing regulated facilities, including transitioning of the CalPeco Electric System to 100% renewable energy and, following the anticipated closing of the acquisition of Ascendant, reducing the reliance on diesel generation at BELCO, replacing it with a combination of renewable energy generation and storage while reducing the cost of electricity to BELCO customers.

Mid-West Wind Development Project

In 2017, the Regulated Services Group presented a plan to the necessary public utility commissions for an investment in up to 600 MW of strategically located wind energy generation which is forecast to reduce energy costs for its customers. The plan consists of development of an approximately 300 MW wind project in southeastern Kansas, and two approximately 150 MW wind projects in southwestern Missouri.

On May 9, 2019, the Arkansas Public Service Commission issued its order allowing the commencement of construction of the projects. In the fourth quarter of 2018, Empire District Electric Company ("Empire") applied to the Missouri Public Service Commission for approval of certificates of CC&N for the projects. The Commission issued an order approving the CC&N application, effective June 29, 2019.

Liberty Utilities Co. has acquired an interest in the entities that own the two Missouri projects and, in partnership with a third-party developer, will continue development and construction of the two Missouri projects. A second third party developer is developing the wind project in Kansas. Empire has entered into contracts to acquire the three wind projects upon completion.

Construction of two of the wind farms began in the fourth quarter of 2019 and construction on the third wind farm began in the first quarter of 2020.

Development of Renewable Energy Assets

The Renewable Energy Group has successfully advanced a number of projects and has been awarded or acquired a number of PPAs and/or long-term hedging arrangements. The projects identified are at various stages of development, and have advanced to a stage where the resolutions to major project uncertainties are probable, but not certain, and it is expected that the project will meet management's risk adjusted return expectations.

The Renewable Energy Group's five-year $2.5 billion pipeline consists of investments in renewable generation projects in North America and indirect international investments. The following table represents the Renewable Energy Group's development and construction projects:

Project Name	Location	Anticipated Size (MW)
Projects in Construction		
Altavista Solar Project[1,2]	Virginia	80
Great Bay II Solar Project	Maryland	45
Maverick Creek Wind Project[1]	Texas	490
Sugar Creek Wind Project[1]	Illinois	202
Val-Eo Phase I Wind Project[1]	Quebec	24
Total Projects in Construction		**841**
Total Projects in Development		**600**
Total Projects in Construction and Development		**1,441**

1 The project is currently held in a joint venture, of which the Renewable Energy Group and a third party each own a 50% equity interest.

2 Power from the project will be sold, in part, to Facebook Operations, LLC, a wholly-owned subsidiary of Facebook, Inc., pursuant to a 12-year PPA.

SUMMARY OF PROPERTY, PLANT, AND EQUIPMENT EXPENDITURES

	Three Months Ended December 31		Twelve Months Ended December 31	
(all dollar amounts in $ millions)	2019	2018	2019	2018
Regulated Services Group				
Rate Base Maintenance	**$ 51.9**	$ 41.5	**$ 194.5**	$ 177.7
Rate Base Growth	**185.1**	76.0	**373.5**	173.9
Property, Plant & Equipment Acquired[1]	**186.2**	—	**186.6**	—
	$ 423.2	$ 117.5	**$ 754.6**	$ 351.6
Renewable Energy Group				
Maintenance	**$ 12.5**	$ 12.6	**$ 37.3**	$ 27.4
Investment in Capital Projects[2]	**(47.1)**	(18.0)	**425.8**	71.6
International Investments[3]	**28.0**	345.0	**122.2**	957.6
	$ (6.6)	$ 339.6	**$ 585.3**	$ 1,056.6
Total Capital Expenditures	**$ 416.6**	$ 457.1	**$ 1,339.9**	$ 1,408.2

1 Property, Plant & Equipment acquired through acquisitions of New Brunswick Gas and St. Lawrence Gas.

2 Includes expenditures on Property Plant & Equipment, equity-method investees, and acquisitions of operating entities that may have been jointly developed by the Company with another third party developer.

3 Investments in Atlantica are reflected at historical investment cost and not fair value.

2019 Fourth Quarter Property Plant and Equipment Expenditures

During the three months ended December 31, 2019, the Regulated Services Group invested $423.2 million ($237.0 million excluding acquisitions) in capital expenditures as compared to $117.5 million during the same period in 2018. The Regulated Services Group's investment was primarily related to the construction of transmission and distribution main replacements, work on new and existing substation assets, initiatives relating to the safety and reliability of the electric and gas systems. The acquisitions of New Brunswick Gas and St. Lawrence Gas added $186.2 million of property, plant and equipment.

The Renewable Energy Group's investment during the quarter was primarily to fund the Altavista and Great Bay II Solar Projects as well as ongoing maintenance capital at existing operating sites. During the quarter, the Maverick Creek and Sugar Creek Wind Joint Ventures reimbursed the Company for funds previously advanced. As a result, the Renewable Energy Group recorded a net reimbursement of $6.6 million during the quarter as compared to capital expenditures of $339.6 million during the same period in 2018.

2019 Annual Property Plant and Equipment Expenditures

During the twelve months ended December 31, 2019, the Regulated Services Group invested $754.6 million in capital expenditures as compared to $351.6 million during the same period in 2018. The Regulated Services Group's investment was primarily related to the construction of transmission and distribution main replacements, the completion and start of work on new and existing substation assets, initiatives relating to the safety and reliability of the electric and gas systems, and investment in the Wataynikaneyap Power Transmission Project. The acquisitions of New Brunswick Gas and St. Lawrence Gas added $186.2 million of property, plant and equipment.

During the twelve months ended December 31, 2019, the Renewable Energy Group incurred capital expenditures of $585.3 million as compared to $1,056.6 million during the same period in 2018. The Renewable Energy Group's investment was primarily related to the purchase of the remaining 50% interest in the Amherst Island Wind Facility from its joint venture partner, development costs for the Altavista and Great Bay II Solar Projects, and Sugar Creek Wind Project, investment in the Vista Ridge Water Pipeline Project, investments into Atlantica; as well as ongoing sustaining capital at existing operating sites.

2020 Capital Investments

Over the course of the 2020 financial year, the Company expects to spend between $1.60 billion - $1.85 billion on capital investment opportunities. Actual expenditures in 2020 may vary due to timing of various project investments and the realized Canadian to U.S. dollar exchange rate.

Ranges of expected capital investment in the 2020 financial year are as follows:

(all dollar amounts in $ millions)			
Regulated Services Group:			
Rate Base Maintenance	$ 200.0	-	$ 250.0
Rate Base Growth	450.0	-	500.0
Rate Base Acquisitions[1]	500.0	-	550.0
Total Regulated Services Group:	$1,150.0	-	$1,300.0
Renewable Energy Group:			
Maintenance	$ 25.0	-	$ 50.0
Investment in Capital Projects	375.0	-	425.0
International Investments	50.0	-	75.0
Total Renewable Energy Group:	$ 450.0	-	$ 550.0
Total 2020 Capital Investments	**$ 1,600.0**	**-**	**$ 1,850.0**

[1] Includes international investments in utilities.

The Regulated Services Group expects to spend between $1,150.0 million - $1,300.0 million over the course of 2020 in an effort to expand our operations, improve the reliability of the utility systems and broaden the technologies used to better serve its service areas. Project spending includes capital for structural improvements, specifically in relation to refurbishing substations, replacing poles and wires, drilling and equipping aquifers, main replacements, and reservoir pumping stations. The Regulated Services Group expects to close the acquisitions of BELCO and the Perris Water Distribution Company in 2020.

The Company expects to fund its 2020 capital plan through a combination of retained cash, tax equity funding, senior debentures, bank revolving and term credit facilities, and common equity and equity like instruments.

The Renewable Energy Group intends to spend between $450.0 million - $550.0 million over the course of 2020 to develop or further invest in capital projects, primarily in relation to: (i) development of the Maverick Creek, Sugar Creek, Shady Oaks II and Blue Hill Wind Projects as well as the Altavista and Great Bay II Solar Projects, and (ii) additional international investments. Furthermore, the Renewable Energy Group plans to spend $25.0 million - $50.0 million on various operational solar, thermal, and wind assets to maintain safety, regulatory, and operational efficiencies.

LIQUIDITY AND CAPITAL RESERVES

APUC has revolving credit and letter of credit facilities as well as separate credit facilities for the Regulated Services Group, and the Renewable Energy Group to manage the liquidity and working capital requirements of each division (collectively the "Bank Credit Facilities").

Bank Credit Facilities

The following table sets out the Bank Credit Facilities available to APUC and its operating groups as at December 31, 2019:

	As at December 31, 2019				As at Dec 31, 2018
(all dollar amounts in $ millions)	**Corporate**	**Regulated Services Group**	**Renewable Energy Group**	**Total**	**Total**
Credit facilities	$ 575.0 [1]	$ 500.0	$ 700.0 [2]	**$ 1,775.0**	$ 1,321.0
Funds drawn on facilities/ Commercial paper issued	(143.0)	(218.0)	—	**(361.0)**	(103.0)
Letters of credit issued	(37.3)	(48.2)	(131.3)	**(216.8)**	(171.1)
Liquidity available under the facilities	**394.7**	**233.8**	**568.7**	**1,197.2**	1,046.9
Cash on hand				**62.5**	46.8
Total Liquidity and Capital Reserves	**$ 394.7**	**$ 233.8**	**$ 568.7**	**$ 1,259.7**	$ 1,093.7

[1] Includes a $75 million uncommitted standalone letter of credit facility.

[2] Includes a $200 million uncommitted standalone letter of credit facility.

On May 23, 2019, the Company fully repaid the remaining outstanding balance of $186.8 million on its corporate term facility in conjunction with the issuance of the Notes (see *Long term Debt*).

On June 27, 2019, the Company extended its $135.0 million corporate term facility to July 6, 2020 and on December 31, 2019, the Company repaid $60.0 million of the facility.

On July 12, 2019, the Company entered into a new $500.0 million senior unsecured credit facility with a syndicate of banks maturing on July 12, 2024 (the "Corporate Credit Facility"). As at December 31, 2019, the Corporate Credit Facility had $143.0 million drawn and had $37.3 million of outstanding letters of credit issued.

On October 24, 2019 the Company entered into a new $75.0 million uncommitted bilateral letter of credit facility. The facility matures on October 24, 2020.

As at December 31, 2019, Regulated Services Group's $500.0 million senior unsecured syndicated revolving credit facility (the "Regulated Services Credit Facility") was undrawn and had $48.2 million of outstanding letters of credit. The Regulated Services Credit Facility matures on February 23, 2023. On July 1, 2019, the Regulated Services Group established a commercial paper program which is backstopped by the Regulated Services Credit Facility. As at December 31, 2019, $218.0 million of commercial paper was issued and outstanding.

As at December 31, 2019, the Renewable Energy Group's bank lines consisted of a $500.0 million senior unsecured syndicated revolving credit facility (the "Renewable Energy Credit Facility") maturing on October 6, 2023 and a $200.0 million letter of credit facility ("Renewable Energy LC Facility") maturing on January 31, 2021. As at December 31, 2019, the Renewable Energy Credit Facility was undrawn and had $6.3 million in outstanding letters of credit. As at December 31, 2019, the Renewable Energy LC Facility had $125.0 million in outstanding letters of credit. Subsequent to year-end, on February 24, 2020, the Renewable Energy Group increased its uncommitted Renewable Energy LC Facility to $350.0 million and extended the maturity to June 30, 2021.

Long Term Debt

Issuance of Senior Notes

On January 29, 2019, the Renewable Energy Group issued C$300.0 million of senior unsecured debentures bearing interest at 4.60% and with a maturity date of January 29, 2029. The debentures were sold at a price of $999.52 per $1000.00 principal amount. The debentures represent Renewable Energy Group's inaugural "green bond" offering, and are closely aligned with the Company's commitment to advancing a sustainable energy and water future.

Subsequent to year-end on February 14, 2020, Liberty Utilities (Canada) LP, the holding company of New Brunswick Gas, issued C$200.0 million of senior unsecured debentures bearing interest at 3.315% and with a maturity date of February 14, 2050. The debentures received a rating of BBB from DBRS. The debentures represent Liberty Utilities (Canada) LP's inaugural offering with proceeds used to partially repay its parent company APUC for the purchase of New Brunswick Gas which occurred on October 1, 2019.

Issuance of Subordinated Notes

On May 23, 2019, APUC issued $350.0 million of 6.20% fixed-to-floating subordinated notes. Concurrent with the offering, APUC entered into a cross currency swap to convert the U.S. dollar denominated coupon and principal payments from the offering into Canadian dollars, resulting in an effective interest rate to the Company throughout the fixed-rate period of the Notes of approximately 5.96%.

The Notes mature 60 years from issuance and are callable on or after year 5. For the initial 5 years, the Notes carry a fixed interest rate of 6.20%. Subsequently, the interest rate will be set to equal the three-month London Interbank Offered Rate ("LIBOR") plus a margin of 401 basis points from years 5 to 10, a margin of 426 basis points from years 10 to 30 and a margin of 501 basis points from years 30 to 60. The Notes were initially assigned a rating of BB+/BB+ from S&P and Fitch. The Notes were treated by both rating agencies as hybrid capital, receiving up to 50% equity credit for the balance outstanding. The Notes contain a 102% of par call feature in the event of a rating methodology change by either agency that would reduce the amount of the equity credit.

This offering represents APUC's second issuance into the U.S. public debt markets. The Notes are listed on the NYSE under the ticker symbol "AQNB".

As at December 31, 2019, the weighted average tenor of APUC's total long term debt is approximately 20 years with an average interest rate of 4.9%.

Credit Ratings

APUC has a long term consolidated corporate credit rating of BBB from Standard & Poor's ("S&P"), a BBB rating from DBRS and a BBB issuer rating from Fitch.

Liberty Utilities Co. ("LUCo"), the parent company for the U.S. regulated utilities under the Regulated Services Group, has a corporate credit rating of BBB from S&P and a BBB issuer rating from Fitch. Debt issued by Liberty Finance, a special purpose financing entity of LUCo, has a rating of BBB (high) from DBRS and BBB+ from Fitch. Empire has an issuer rating of BBB from S&P and a Baa1 rating from Moody's Investors Service, Inc. ("Moody's").

Liberty Utilities (Canada) LP, the parent company for the Canadian regulated utilities under the Regulated Services Group has an issuer rating of BBB from DBRS.

Liberty Power, the parent company for the U.S. and Canadian generating assets under the Renewable Energy Group, has a BBB issuer rating from S&P, a BBB issuer rating from DBRS and a BBB issuer rating from Fitch.

Contractual Obligations

Information concerning contractual obligations as of December 31, 2019 is shown below:

(all dollar amounts in $ millions)	Total	Due in less than 1 year	Due in 1 to 3 years	Due in 4 to 5 years	Due after 5 years
Principal repayments on debt obligations[1,2]	**$ 3,931.8**	$ 602.0	$ 468.7	$ 600.7	$ 2,260.4
Convertible debentures	**0.3**	—	—	—	0.3
Advances in aid of construction	**60.9**	1.2	—	—	59.7
Interest on long-term debt obligations[2]	**1,753.2**	185.2	318.5	257.4	992.1
Purchase obligations	**458.3**	458.3	—	—	—
Environmental obligations	**58.5**	15.0	20.9	1.1	21.5
Derivative financial instruments:					
Cross currency and forward starting interest rate swaps	**81.8**	4.1	69.1	3.9	4.7
Energy derivative and commodity contracts	**2.9**	1.6	0.9	—	0.4
Purchased power	**256.3**	30.7	22.8	23.4	179.4
Gas delivery, service and supply agreements	**416.8**	83.1	109.9	87.9	135.9
Service agreements	**516.0**	48.0	82.0	92.6	293.4
Capital projects	**219.6**	104.8	114.8	—	—
Land easements	**234.7**	6.6	13.4	13.8	200.9
Other obligations	**153.0**	39.1	2.1	2.7	109.1
Total Obligations	**$ 8,144.1**	**$ 1,579.7**	**$ 1,223.1**	**$ 1,083.5**	**$ 4,257.8**

1 Exclusive of deferred financing costs, bond premium/discount, fair value adjustments at the time of issuance or acquisition.

2 The subordinated notes have a maturity in 2078 and 2079, however management intends to repay in 2023 and 2029 upon exercising its redemption right.

Equity

The common shares of APUC are publicly traded on the Toronto Stock Exchange ("TSX") and the New York Stock Exchange ("NYSE") under the trading symbol "AQN". As at February 26, 2020, APUC had 525,624,407 issued and outstanding common shares.

APUC may issue an unlimited number of common shares. The holders of common shares are entitled to dividends, if and when declared; to one vote for each share at meetings of the holders of common shares; and to receive a pro rata share of any remaining property and assets of APUC upon liquidation, dissolution or winding up of APUC. All shares are of the same class and with equal rights and privileges and are not subject to future calls or assessments.

APUC is also authorized to issue an unlimited number of preferred shares, issuable in one or more series, containing terms and conditions as approved by the Board. As at December 31, 2019, APUC had outstanding:

- 4,800,000 cumulative rate reset Series A preferred shares, yielding 5.162% annually for the five-year period ending on December 31, 2023;
- 100 Series C preferred shares that were issued in exchange for 100 Class B limited partnership units by St. Leon Wind Energy LP; and
- 4,000,000 cumulative rate reset Series D preferred shares, yielding 5.091% annually for the five year period ending on March 31, 2024.

On October 16, 2019, APUC closed the sale of 23.0 million of its common shares for total gross proceeds of $310.5 million, before deducting underwriting commissions and other offering expenses payable by APUC. APUC also granted the underwriters an option to purchase up to an additional 3.5 million common shares of the Company for a period of 30 days. On October 21, 2019, APUC closed the sale of approximately 3.3 million of its common shares for total gross proceeds of $43.9 million, before deducting underwriting commissions payable by APUC.

The proceeds of the Offering were or will be used (as applicable) to partially finance certain of the Company's previously announced acquisitions and to partially finance the Company's renewable development growth projects, and for general corporate purposes.

Dividend Reinvestment Plan

APUC has a shareholder dividend reinvestment plan (the "Reinvestment Plan") for registered holders of common shares of APUC. As at December 31, 2019, 123,468,295 common shares representing approximately 24% of total common shares outstanding had been registered with the Reinvestment Plan. During the year ended December 31, 2019, 6,068,465 common shares were issued under the Reinvestment Plan, and subsequent to year-end, on January 15, 2020, an additional 1,244,696 common shares were issued under the Reinvestment Plan.

At-The-Market Equity Program

On February 28, 2019, APUC established an at-the market equity program ("ATM Program") that allows APUC to issue up to $250.0 million (or the equivalent in Canadian dollars) of common shares from treasury to the public from time to time, at APUC's discretion, at the prevailing market price when issued on the TSX, the NYSE, or on any other existing trading market for the common shares of the Company in Canada or the United States. The ATM Program will be effective until October 19, 2020 unless terminated prior to such date by APUC or otherwise in accordance with the terms of the equity distribution agreement dated February 28, 2019.

The ATM Program provides APUC with additional financing flexibility should it be required in the future. The volume and timing of distributions under the ATM Program, will be determined at APUC's sole discretion. The net proceeds, will be used to fund acquisitions, general and administrative expenses, working capital needs, repayment of indebtedness, and/or other general corporate purposes.

As at February 27, 2020, the Company has issued 1,756,799 common shares under the ATM Program at an average price of $12.54 per share for gross proceeds of approximately $22.0 million ($21.7 million net of commissions). Other related costs, primarily related to the establishment of the ATM Program, were $2.1 million.

SHARE-BASED COMPENSATION PLANS

For the twelve months ended December 31, 2019, APUC recorded $10.6 million in total share-based compensation expense as compared to $9.5 million for the same period in 2018. The compensation expense is recorded as part of administrative expenses in the consolidated statement of operations. The portion of share-based compensation costs capitalized as cost of construction is insignificant.

As at December 31, 2019, total unrecognized compensation costs related to non-vested options and share unit awards were $1.3 million and $12.8 million, respectively, and are expected to be recognized over a period of 1.68 and 1.86 years, respectively.

Stock Option Plan

APUC has a stock option plan that permits the grant of share options to key officers, directors, employees and selected service providers. Except in certain circumstances, the term of an option shall not exceed ten (10) years from the date of the grant of the option.

APUC determines the fair value of options granted using the Black-Scholes option-pricing model. The estimated fair value of options, including the effect of estimated forfeitures, is recognized as an expense on a straight-line basis over the options' vesting periods while ensuring that the cumulative amount of compensation cost recognized at least equals the value of the vested portion of the award at that date. During the twelve months ended December 31, 2019, the Company granted 1,113,775 options to executives of the Company. The options allow for the purchase of common shares at a weighted average price of C$14.96, the market price of the underlying common share at the date of grant. During the year, executives of the Company exercised 841,288 stock options at a weighted average exercise price of C$11.23 in exchange for common shares issued from treasury and 3,041,217 options were settled at their cash value as payment for the exercise price and tax withholdings related to the exercise of the options.

As at December 31, 2019, a total of 3,523,912 options were issued and outstanding under the stock option plan.

Performance Share Units

APUC issues performance share units ("PSUs") and restricted share units ("RSUs") to certain members of management as part of APUC's long-term incentive program. During the twelve months ended December 31, 2019, the Company granted (including dividends and performance adjustments) 1,471,442 PSUs and RSUs to executives and employees of the Company. During the year, the Company settled 344,340 PSUs, of which 142,473 PSUs were exchanged for common shares issued from treasury and 143,078 PSUs were settled at their cash value as payment for tax withholdings related to the settlement of the PSUs. Additionally, during 2019, a total of 107,191 PSUs were forfeited.

As at December 31, 2019, a total of 2,412,043 PSUs and RSUs were granted and outstanding under the PSU and RSU plans.

Directors' Deferred Share Units

APUC has a Directors' Deferred Share Unit Plan. Under the plan, non-employee directors of APUC receive all or any portion of their annual compensation in deferred share units ("DSUs") and may elect to receive any portion of their remaining compensation in DSUs. The DSUs provide for settlement in cash or shares at the election of APUC. As APUC does not expect to settle the DSUs in cash, these DSUs are accounted for as equity awards. During the twelve months ended December 31, 2019, the Company issued 79,762 DSUs (including DSUs in lieu of dividends) to the directors of the Company.

As at December 31, 2019, a total of 460,418 DSUs had been granted under the DSU plan.

Bonus Deferral Restricted Share Units

The Company has a bonus deferral restricted share units ("RSUs") program that is available to certain employees. The eligible employees have the option to receive a portion or all of their annual bonus payment in RSUs in lieu of cash. The RSUs provide for settlement in shares, and therefore these options are accounted for as equity awards. During the twelve months ended December 31, 2019, 262,390 RSUs were issued (including RSUs in lieu of dividends) to employees of the Company.

Employee Share Purchase Plan

APUC has an Employee Share Purchase Plan (the "ESPP") which allows eligible employees to use a portion of their earnings to purchase common shares of APUC. The aggregate number of shares reserved for issuance from treasury by APUC under this plan shall not exceed 2,000,000 shares. During the twelve months ended December 31, 2019, the Company issued 253,538 common shares to employees under the ESPP.

As at December 31, 2019, a total of 1,285,789 shares had been issued under the ESPP.

MANAGEMENT OF CAPITAL STRUCTURE

APUC views its capital structure in terms of its debt and equity levels at its individual operating groups and at an overall company level.

APUC's objectives when managing capital are:

- To maintain its capital structure consistent with investment grade credit metrics appropriate to the sectors in which APUC operates;
- To maintain appropriate debt and equity levels in conjunction with standard industry practices and to limit financial constraints on the use of capital;
- To ensure capital is available to finance capital expenditures sufficient to maintain existing assets;
- To ensure generation of cash is sufficient to fund sustainable dividends to shareholders as well as meet current tax and internal capital requirements;
- To maintain sufficient liquidity to ensure sustainable dividends made to shareholders; and
- To have appropriately sized revolving credit facilities available for ongoing investment in growth and development opportunities.

APUC monitors its cash position on a regular basis to ensure funds are available to meet current normal as well as capital and other expenditures. In addition, APUC continuously reviews its capital structure to ensure its individual business groups are using a capital structure which is appropriate for their respective industries.

RELATED PARTY TRANSACTIONS

Equity-method investments

The Company entered in a number of transactions with equity-method investees in 2019 and 2018 (see *Note 8* in the annual audited consolidated financial statements).

The Company provides administrative and development services to its equity-method investees and is reimbursed for incurred costs. To that effect, the Company charged its equity-method investees $12.4 million in 2019 as compared to $11.4 million during the same period in 2018 (see *Note 8(d)* and *8(e)* in the annual audited consolidated financial statements).

On December 30, 2019, the Company sold its interest in AWUSA VR Holding LLC ("AWUSA") to a joint venture entity in exchange for a note receivable of $30.3 million (see *Note 8(c)* in the annual audited consolidated financial statements). No gain or loss was recognized on the sale. For the year, APUC recorded interest income of $6.0 million and a fair value loss of $6.0 million on its investment in the joint venture.

During the year, the Company sold the Sugar Creek Wind Project to AAGES in exchange for a note receivable of $21.1 million, subject to certain adjustments. No gain was recorded on deconsolidation of the Sugar Creek Wind Project net assets. However, an amount of $15.8 million or $11.4 million, net of tax was reclassified from AOCI into earnings as a result of the discontinuation of hedge accounting on energy derivatives put in place early in the development of the Sugar Creek Wind Project (see *Note 24(b)(ii)* in the annual audited consolidated financial statements).

During the year, the Company entered into an enhanced cooperation agreement with Atlantica to, among other things, provide a framework for evaluating mutually advantageous transactions. For a period of one year from the date of the agreement, Atlantica has an exclusive right of first offer for interests in certain Renewable Energy Group assets.

Redeemable non-controlling interest held by related party

Redeemable non-controlling interest held by related party represents a preference share in a consolidated subsidiary of the Company acquired by AAGES in 2018 for $305.0 million (see *Note 8(a)* in the annual audited consolidated financial statements). Redemption is not considered probable as at December 31, 2019. The Company incurred non-controlling interest attributable to AAGES of $16.5 million as compared to $2.6 million during the same period in 2018 and recorded distributions of $18.2 million as compared to $nil during the same period in 2018 (see *Note 17* in the annual audited consolidated financial statements).

Non-controlling interest held by related party

Non-controlling interest held by related party represents interest in a consolidated subsidiary of the Company acquired by a subsidiary of Atlantica in May 2019 for $96.8 million (see *Note 8(b)* in the annual audited consolidated financial statements). The Company recorded distributions of $26.5 million during the year.

Long Sault Hydro Facility

Effective December 31, 2013, APUC acquired the shares of Algonquin Power Corporation Inc. ("APC") which was partially owned by Senior Executives. APC owns the partnership interest in the 18 MW Long Sault Hydro Facility. A final post-closing adjustment related to the transaction remains outstanding.

The above related party transactions have been recorded at the exchange amounts agreed to by the parties to the transactions.

ENTERPRISE RISK MANAGEMENT

The Corporation is subject to a number of risks and uncertainties, certain of which are described below. A risk is the possibility that an event might happen in the future that could have a negative effect on the financial condition, financial performance or business of the Corporation. The actual effect of any event on the Corporation's business could be materially different from what is anticipated or described below. The description of risks below does not include all possible risks.

Led by the Chief Compliance and Risk Officer, the Corporation has an established enterprise risk management, or ("ERM"), framework. The Corporation's ERM framework follows the guidance of ISO 31000 and the Committee of Sponsoring Organizations of the Treadway Commission ("COSO") Enterprise Risk Management - Integrated Framework. The Corporation's ERM framework is intended to systematically identify, assess, and mitigate the key strategic, operational, financial, and compliance risks that may impact the achievement of the Corporation's current objectives, as well as those inherent to strategic alternatives available to the Corporation. The Corporation's Board-approved ERM policy details the Corporation's risk management processes, risk appetite, and risk governance structure.

As part of the risk management process, risk registers have been developed across the organization through ongoing risk identification and risk assessment exercises facilitated by the Corporation's internal ERM team. Key risks and associated mitigation strategies are reviewed by the executive-level Enterprise Risk Management Council and are presented to the Board's Risk Committee periodically.

Risks are evaluated consistently across the Corporation using a standardized risk scoring matrix to assess impact and likelihood. Financial, reputational and safety implications are among those considered when determining the impact of a potential risk. Risk treatment priorities are established based upon these risk assessments and incorporated into the development of the Corporation's strategic and business plans.

The risks discussed below are not intended as a complete list of all exposures that APUC is encountering or may encounter. A further assessment of APUC and its subsidiaries' risk factors are set out in the Company's most recent AIF available on SEDAR and EDGAR. The risks discussed below are intended to provide an update on those that were previously disclosed.

Treasury Risk Management

Downgrade in the Company's Credit Rating Risk

APUC has a long term consolidated corporate credit rating of BBB from S&P, a BBB rating from DBRS and a BBB issuer rating from Fitch. Liberty Power, the parent company for the U.S. and Canadian generating assets under the Renewable Energy Group, has a BBB issuer rating from S&P, BBB issuer rating from DBRS and a BBB issuer rating from Fitch. LUCo, the parent company for the U.S. regulated utilities under the Regulated Services Group, has a corporate credit rating of BBB from S&P and a BBB issuer rating from Fitch. Debt issued by Liberty Finance, a special purpose financing entity of LUCo, has a rating of BBB (high) from DBRS and BBB+ from Fitch. Empire has a BBB issuer rating from S&P and a Baa1 issuer rating from Moody's. Liberty Utilities (Canada) LP, the parent company for the Canadian regulated utilities under the Regulated Services Group has an issuer rating of BBB from DBRS.

The ratings indicate the agencies' assessment of the ability to pay the interest and principal of debt securities issued by such entities. A rating is not a recommendation to purchase, sell or hold securities and each rating should be evaluated independently of any other rating. The lower the rating, the higher the interest cost of the securities when they are sold. A downgrade in APUC's or its subsidiaries' issuer corporate credit ratings would result in an increase in APUC's borrowing costs under its bank credit facilities and future long-term debt securities issued. Any such downgrade could also adversely impact the market price of the outstanding securities of the Company, could impact the Company's ability to acquire additional regulated utilities and could require the Company to post additional collateral security under some of its contracts and hedging arrangements. If any of APUC's ratings fall below investment grade (investment grade is defined as BBB- or above for S&P and Fitch, BBB (low) or above for DBRS and Baa3 or above for Moody's), APUC's ability to issue short-term debt or other securities or to market those securities would be constrained or made more difficult or expensive. Therefore, any such downgrades could have a material adverse effect on APUC's business, cost of capital, financial condition and results of operations.

The Company is not adopting or endorsing such ratings, and such ratings do not indicate APUC's assessment of its own ability to pay the interest or principal of debt securities it issues. The Company is providing such ratings only to assist with the assessment of future risks and effects of ratings on the Company's financing costs.

No assurances can be provided that any of APUC's current ratings will remain in effect for any given period of time or that a rating will not be lowered or withdrawn entirely by a rating agency if, in its judgment, circumstances in the future so warrant. Each rating agency employs proprietary scoring methodologies that assess business and financial risks of the entity rated. There can be no assurance that the principles of the rating remain consistently applied, and these principles are subject to change from time to time at each rating agency's discretion. For example, a rating agency's views on total allowable leverage, specific industry risk factors, country risk and the company's business mix, amongst other factors, may change. Such changes could require APUC to adjust its business and strategy in order to maintain its credit ratings. APUC currently anticipates that to continue to maintain a BBB flat investment grade credit ratings, it will, amongst other things, need to execute its growth strategy in a manner that preserves satisfaction of financial leverage targets and continues to generate no less than approximately its current portion of EBITDA (as determined by applicable rating agency methodologies) from APUC's Regulated Services Group. There can be no assurance that APUC will be successful, and the failure to do so could have a negative impact on APUC's credit ratings. The business mix target may from time to time require APUC to grow its Regulated Services Group or implement other strategies in order to pursue investment opportunities within its Renewable Energy Group.

Capital Markets and Liquidity Risk

As at December 31, 2019, the Company had approximately $3,932.2 million of long-term consolidated indebtedness. Management of the Company believes, based on its current expectations as to the Company's future performance, that the cash flow from its operations and funds available to it under its revolving credit facilities and its ability to access capital markets will be adequate to enable the Company to finance its operations, execute its business strategy and maintain an adequate level of liquidity. However, expected revenue and capital expenditures are only estimates. Moreover, actual cash flows from operations are dependent on regulatory, market and other conditions that are beyond the control of the Company. As such, no assurance can be given that management's expectations as to future performance will be realized.

The ability of the Company to raise additional debt or equity or to do so on favourable terms may be adversely affected by adverse financial and operational performance, or by financial market disruptions or other factors outside the control of the Company.

In addition, the Company may at times incur indebtedness in excess of its long-term leverage targets, in advance of raising the additional equity necessary to repay such indebtedness and maintain its long-term leverage target. Any increase in the Company's leverage could, among other things, limit the Company's ability to obtain additional financing for working capital, investment in subsidiaries, capital expenditures, debt service requirements, acquisitions and general corporate or other purposes; restrict the Company's flexibility and discretion to operate its business; limit the Company's ability to declare dividends; require the Company to dedicate a portion of cash flows from operations to the payment of interest on its existing indebtedness, in which case such cash flows will not be available for other purposes; cause ratings agencies to re-evaluate or downgrade the Company's existing credit ratings; expose the Company to increased interest expense on borrowings at variable rates; limit the Company's ability to adjust to changing market conditions; place the Company at a competitive disadvantage compared to its competitors; make the Company vulnerable to any downturn in general economic conditions; and render the Company unable to make expenditures that are important to its future growth strategies.

The Company will need to refinance or reimburse amounts outstanding under the Company's existing consolidated indebtedness over time. There can be no assurance that any indebtedness of the Company will be refinanced or that additional financing on commercially reasonable terms will be obtained, if at all. In the event that such indebtedness cannot be refinanced, or if it can be refinanced on terms that are less favourable than the current terms, the Company's cashflows and the ability of the Company to declare dividends may be adversely affected.

The ability of the Company to meet its debt service requirements will depend on its ability to generate cash in the future, which depends on many factors, including the financial performance of the Company, debt service obligations, the realization of the anticipated benefits of acquisition and investment activities, and working capital and capital expenditure requirements. In addition, the ability of the Company to borrow funds in the future to make payments on outstanding debt will depend on the satisfaction of covenants in existing credit agreements and other agreements. A failure to comply with any covenants or obligations under the Company's consolidated indebtedness could result in a default under one or more such instruments, which, if not cured or waived, could result in the termination of dividends by the Company and permit acceleration of the relevant indebtedness. If such indebtedness were to be accelerated, there can be no assurance that the assets of the Company would be sufficient to repay such indebtedness in full. There can also be no assurance that the Company will generate cash flows in amounts sufficient to pay outstanding indebtedness or to fund any other liquidity needs.

Interest Rate Risk

The majority of debt outstanding in APUC and its subsidiaries is subject to a fixed rate of interest and as such is not subject to significant interest rate risk in the short to medium term time horizon.

Borrowings subject to variable interest rates can vary significantly from month to month, quarter to quarter and year to year. APUC does not actively manage interest rate risk on its variable interest rate borrowings due to the primarily short term and revolving nature of the amounts drawn.

Based on amounts outstanding as at December 31, 2019, the impact to interest expense from changes in interest rates are as follows:

- The Corporate Credit Facility is subject to a variable interest rate and had $143.0 million outstanding as at December 31, 2019. As a result, a 100 basis point change in the variable rate charged would impact interest expense by $1.4 million annually;
- The Regulated Services Group's commercial paper program is subject to a variable interest rate and had $218.0 million outstanding as at December 31, 2019. As a result, a 100 basis point change in the variable rate charged would impact interest expense by $2.2 million annually;
- The corporate term facilities are subject to a variable interest rate and had $75.0 million outstanding as at December 31, 2019. As a result, a 100 basis point change in the variable rate charged would impact interest expense by $0.8 million annually.

Tax Risk and Uncertainty

The Company is subject to income and other taxes primarily in the United States and Canada. Changes in tax laws or interpretations thereof in the jurisdictions in which it does business could adversely affect the Company's results from operations, returns to shareholders and cash flow.

The Company cannot provide assurance that the Canada Revenue Agency, the Internal Revenue Service or any other applicable taxation authority will agree with the tax positions taken by the Company, including with respect to claimed expenses and the cost amount of the Company's depreciable properties. A successful challenge by an applicable taxation authority regarding such tax positions could adversely affect the results of operations and financial position of the Company.

Development by the Company of renewable power generation facilities in the United States depends in part on federal tax credits and other tax incentives. These credits are currently subject to a multi-year step-down. While recently enacted U.S. Tax Reform legislation did extend some of the credits, at reduced levels, for renewable power generation facilities that begin construction in 2020, there can be no assurance that there will be further extensions in the future or whether the reduced credits are sufficient to support continued development and construction of renewable power facilities in the United States. Moreover, if the Company is unable to complete construction on current or planned projects on anticipated schedules, the incentives may no longer be available or substantially reduced which may be insufficient to support continued development or may result in substantially reduced financial benefits from facilities or long-term investment in facilities (potentially resulting in a write down of a portion of a facility whether held directly or through an equity investee) that the Company is committed to complete. In addition, the Company has entered into certain tax equity financing transactions with financial partners for certain of its renewable power facilities in the United States, under which allocations of future cash flows to the Corporation from the applicable facility could be adversely affected in the event that there are changes in U.S. tax laws that apply to facilities previously placed in service.

U.S. Tax Reform

On December 22, 2017, H.R. 1, the Tax Cuts and Jobs Act was signed into law which resulted in significant changes to U.S. tax law that affect the Company. The U.S. Department of Treasury has released proposed regulations related to business interest expense limitations, Base Erosion Anti-Abuse Tax, and anti-hybrid structures as part of the implementation of U.S. Tax Reform. Some of the proposed regulations were finalized during 2019. Many of the regulations are still in proposed form and are subject to change in the regulatory review process which is expected to be completed during 2020. The timing or impacts of any future changes in tax laws, including the impacts of proposed regulations, cannot be predicted. As a result, there may be future impacts on the results of operations, financial condition and cash flows of the Company.

Credit/Counterparty Risk

APUC and its subsidiaries, through its long term PPA's, trade receivables, derivative financial instruments and short term investments, are subject to credit risk with respect to the ability of customers and other counterparties to perform their obligations to the Company.

The following chart sets out the Company's 10 largest customers and their credit ratings:

Counterparty	Credit Rating [1]		Approximate Annual Revenues	Percentage of APUC Revenue
PJM Interconnection LLC	Aa2	$	25.6	1.6%
Manitoba Hydro	A+		22.4	1.4%
Hydro Quebec	Aa2		20.4	1.3%
Commonwealth Edison	A-		22.1	1.4%
Xcel Energy	Baa1		17.5	1.1%
Pacific Gas and Electric Company	D		18.9	1.2%
Wolverine Power Supply	A		23.6	1.5%
Ontario Electricity Financial Corporation (OEFC)	Aa3		16.1	1.0%
Connecticut Light and Power	A3		19.9	1.2%
Independent Electricity System Operator (IESO) of Ontario	Aa3		15.9	1.0%
Total		**$**	**202.4**	

1 Ratings by DBRS, Moody's, or S&P.

The Renewable Energy Group's revenues are approximately 15% of total Company revenues. Approximately 87% of the Renewable Energy Group's revenues are earned from large utility customers having a credit rating of Baa2 or better by Moody's, or BBB or higher by S&P, or BBB or higher by DBRS.

The remaining revenue of the Company is primarily earned by the Regulated Services Group. In this regard, the credit risk attributed to the Regulated Services Group's accounts receivable balances at the water and wastewater distribution systems total $22.1 million which is spread over approximately 168,000 connections, resulting in an average outstanding balance of approximately $130 dollars per connection.

The natural gas distribution systems accounts receivable balances related to the natural gas utilities total $99.3 million, while electric distribution systems accounts receivable balances related to the electric utilities total $90.8 million. The natural gas and electrical utilities both derive over 80% of their revenue from residential customers and have a per connection average outstanding balance of $269 dollars and $340 dollars respectively.

Adverse conditions in the energy industry or in the general economy, as well as circumstances of individual customers or counterparties, may adversely affect the ability of a customer or counterparty to perform as required under its contract with the Company. Losses from a utility customer may not be offset by bad debt reserves approved by the applicable utility regulator. If a customer under a long-term PPA with the Renewable Energy Group is unable to perform, the Renewable Energy Group may be unable to replace the contract on comparable terms, in which case sales of power (and, if applicable, RECs and ancillary services) from the facility would be subject to market price risk and may require refinancing of indebtedness related to the facility or otherwise have a material adverse effect. Default by other counterparties, including counterparties to hedging contracts that are in an asset position and to short-term investments, also could adversely affect the financial results of the Corporation.

Market Price Risk

The Renewable Energy Group assets subject to long term PPA's are not exposed to market risk for this portion of its portfolio. Where a generating asset is not covered by a PPA, the Renewable Energy Group may seek to mitigate market risk exposure by entering into financial or physical power hedges requiring that a specified amount of power be delivered at a specified time in return for a fixed price. There is a risk that the Company is not able to generate the specified amount of power at the specified time resulting in production shortfalls under the hedge that then requires the Company to purchase power in the merchant market. To mitigate the risk of production shortfalls under hedges, the Renewable Energy Group generally seeks to structure hedges to cover less than 100% of the anticipated production, thereby reducing the risk of not producing the minimum hedge quantities. Nevertheless, due to unpredictability in the natural resource or due to grid curtailments or mechanical failures, production shortfalls may be such that the Renewable Energy Group may still be forced to purchase power in the merchant market at prevailing rates to settle against a hedge.

Hedges currently put in place by the Renewable Energy Group for its operating facilities along with residual exposures to the market are detailed below:

The Minonk, Senate and Sandy Ridge Wind Facilities with a combined annual LTAR of 1,352 GW-hrs have financial hedges in place until the end of 2025 which are structured to hedge an average of 66.3% of annual LTAR against exposure to the applicable hub current spot market rates. The annual average unhedged production based on LTAR is approximately 455 GW-hrs annually.

Under each of the above noted hedges, if production is not sufficient to meet the unit quantities under the hedge, the shortfall must be purchased in the open market at market rates. The effect of this risk exposure could be material but cannot be quantified as it is dependent on both the amount of shortfall and the market price of electricity at the time of the shortfall.

In addition to the above noted hedges, from time to time the Renewable Energy Group enters into short-term derivative contracts (usually with terms of one to three months) to further mitigate market price risk exposure due to production variability. As at December 31, 2019, the Renewable Energy Group had entered into hedges with a cumulative notional quantity of 148,520 MW-hrs.

The January 1, 2013 acquisition of the Shady Oaks Wind Facility included a power sales contract, which commenced on June 1, 2012 for a 20 year period. The power sales contract is structured to hedge the preponderance of the Shady Oaks Wind Facility's production volume against exposure to PJM ComEd Hub current spot market rates. For the unhedged portion of production based on expected long term average production, each $10 per MW-hr change in market prices would result in a change in revenue of approximately $0.5 million for the year.

The Company has elected the fair value option under ASC 825, *Financial Instruments* to account for its investment in Atlantica, with changes in fair value reflected in the annual audited consolidated statement of operations. As a result, each dollar change in the traded price of Atlantica shares will correspondingly affect the Company's Net Earnings by approximately $44.9 million.

Commodity Price Risk

The Regulated Services Group is exposed to energy and natural gas price risks at its electric and natural gas systems. The Renewable Energy Group's exposure to commodity prices is primarily limited to exposure to natural gas price risk. In this regard, a discussion of these risks are set out as follows:

Regulated Services Group

The CalPeco Electric System provides electric service to the Lake Tahoe California basin and surrounding areas at rates approved by the California Public Utilities Commission ("CPUC"). The CalPeco Electric System purchases the energy, capacity, and related service requirements for its customers from NV Energy via a PPA at rates reflecting NV Energy's system average costs.

The CalPeco Electric System's tariffs allow for the pass-through of energy costs to its rate payers on a dollar for dollar basis, through the ECAC mechanism, which allows for the recovery or refund of changes in energy costs that are caused by the fluctuations in the price of fuel and purchased power. On a monthly basis, energy costs are compared to the CPUC approved base tariff energy rates and the difference is deferred to a balancing account. Annually, based on the balance of the ECAC balancing account, if the ECAC revenues were to increase or decrease by more than 5%, the CalPeco Electric System's ECAC tariff allows for a potential adjustment to the ECAC rates which would eliminate the risk associated with the fluctuating cost of fuel and purchased power.

The Granite State Electric System is an open access electric utility allowing for its customers to procure commodity services from competitive energy suppliers. For those customers that do not choose their own competitive energy supplier, Granite State Electric System provides a Default Service offering to each class of customers through a competitive bidding process. This process is undertaken semi-annually for all Default Service customers. The winning bidder is obligated to provide a full requirements service based on the actual needs of the Granite State Electric System's Default Service customers. Since this is a full requirements service, the winning bidder(s) take on the risk associated with fluctuating customer usage and commodity prices. The supplier is paid for the commodity by the Granite State Electric System which in turns receives pass-through rate recovery through a formal filing and approval process with the NHPUC on a semi-annual basis. The Granite State Electric System is only committed to the winning Default Service supplier(s) after approval by the NHPUC so that there is no risk of commodity commitment without pass-through rate recovery.

The EnergyNorth Natural Gas System purchases pipeline capacity, storage and commodity from a variety of counterparties. The EnergyNorth Natural Gas System's portfolio of assets and its planning and forecasting methodology are commonly approved by the NHPUC bi-annually through Least Cost Integrated Resource Plan filing. In addition, EnergyNorth Natural Gas System files with the NHPUC for recovery of its transportation and commodity costs on a semi-annual basis through the Cost of Gas ("COG") filing and approval process. The EnergyNorth Natural Gas System establishes rates for its customers based on the NHPUC approval of its filed COG. These rates are designed to fully recover its anticipated transportation and commodity costs. In order to minimize commodity price fluctuations, the EnergyNorth Natural Gas System locks in a fixed price basis for approximately 18% of its normal winter period purchases under a NHPUC approved hedging program. All costs associated with the fixed basis hedging program are allowed to be a pass-through to customers through the COG filing and the approved rates in said filing. Should commodity prices increase or decrease relative to the initial semi-annual COG rate filing, the EnergyNorth Natural Gas System has the right to automatically adjust its rates going forward in order to minimize any under or over collection of its gas costs. In addition, any under collections may be carried forward with interest to the next year's corresponding COG filing, i.e. winter to winter and summer to summer.

The Midstates Gas Systems purchases pipeline capacity, storage and commodity from a variety of counterparties, and files with the three individual state commissions for recovery of its transportation and commodity costs through an annual Purchase Gas Adjustment ("PGA") filing and approval process. The Midstates Gas Systems establishes rates for its customers within the PGA filing and these rates are designed to fully recover its anticipated transportation, storage and commodity costs. In order to minimize commodity price fluctuations, the Company has implemented a commodity hedging program designed to hedge approximately 25-50% of its non-storage related commodity purchases. All gains and losses associated with the hedging program are allowed to be a pass-through to customers through the PGA filing and are embedded in the approved rates in said filing. Rates can be adjusted on a monthly or quarterly basis in order to account for any commodity price increase or decrease relative to the initial PGA rate, minimizing any under or over collection of its gas costs. Similar to the Midstates Gas Systems, the Empire Gas System serves customers in Missouri, and also implements a commodity hedging program designed to hedge 70 to 90% of its winter demand inclusive of storage volumes withdrawn during the winter period. All related costs are embedded in approved rates and are passed-through to customers in the PGA. The Empire Gas System is permitted to file an Actual Cost Adjustment ("ACA") once a year which also includes a PGA filing. In addition to the ACA filing, three more optional PGA filings are allowed during the year. The Empire Gas Systems ACA year is from September 1 to August 31 for each year.

The Georgia (Peach State) Gas System purchases pipeline capacity, storage and commodity from a variety of counterparties, and files with the Georgia Public Service Commission ("PSC") for recovery of its transportation, storage and commodity costs through a monthly PGA filing process. The Peach State Gas System establishes rates for its customers within the PGA filings and these rates are designed to fully recover its anticipated transportation, storage and commodity costs. In order to minimize commodity price fluctuations, the annual Gas Supply Plan filed by the Company and approved by the Georgia PSC includes a commodity hedging program designed to hedge approximately 30% of its non-storage related commodity purchases during the winter months. All gains and losses associated with the hedging program are passed through to customers in the PGA filings and are embedded in the approved rates in such filings. Rates can be adjusted on a monthly basis in order to account for any differences in gas costs relative to the amounts assumed in the PGA filings, minimizing any under or over collection of its gas costs.

The Empire Electric System has a fuel cost recovery mechanism in all of its jurisdictions, as such impacts on net income exposure to commodity cost fluctuations are significantly reduced. However, cash flow could still be impacted by any increased expenditures. The Empire Electric System met approximately 41% of its 2019 generation fuel supply need through coal. Approximately 97% of its 2019 coal supply was Western coal. The Empire Electric System had contracts and binding proposals to supply a portion of the fuel for its coal plants through 2019. Those contracts and inventory on hand satisfied the anticipated fuel requirements for the Asbury Coal Facility. The Asbury Coal Facility is scheduled to be retired in March 2020.

The Empire Electric Systems natural gas procurement program for electrical generation is designed to manage costs to mitigate volatile natural gas prices. The Empire Electric System periodically enters into fixed price contracts with counterparties to hedge future natural gas prices in an attempt to lessen the volatility in fuel expenditures. Generally, the over/under variances associated with the hedging program are passed through to customers in the fuel adjustment clause assuming they are deemed to be prudently incurred.

Renewable Energy Group

The Sanger Thermal Facility's PPA includes provisions which reduce its exposure to natural gas price risk. In this regard, a $1.00 increase in the price of natural gas per MMBTU, based on expected production levels, would result in a decrease in net revenue by approximately $0.1 million on an annual basis.

The Windsor Locks Thermal Facility's Energy Services Agreement includes provisions which reduce its exposure to natural gas price risk but has exposure to market rate conditions for sales above those to its primary customer. In this regard, a $1.00 increase in the price of natural gas per MMBTU, based on expected production levels, would result in a decrease in net revenue by approximately $0.4 million on an annual basis.

The Maritime region provides short-term energy requirements to various customers at fixed rates. The energy requirements of these customers are estimated at approximately 190,000 MW-hrs in fiscal 2020, of which 181,000 MW-hrs is presently contracted. While the Tinker Hydro Facility is expected to provide the majority of the energy required to service these customers, the Maritime region anticipates having to purchase approximately 41,000 MW-hrs of its energy requirements at the ISO-NE spot rates to supplement self-generated energy should the Maritime region not be able to reach the estimated 190,000 MW-hrs. The risk associated with the expected market purchases of 41,000 MW-hrs is mitigated through the use of financial energy hedge contracts which cover all of the Maritime region's anticipated purchases during the year at an average rate of approximately $39 per MW-hr.

OPERATIONAL RISK MANAGEMENT

Succession Planning and Leadership Development

On February 5, 2020, APUC announced the appointment of Arun Banskota to the newly-created position of President. Mr. Banskota will work closely with Chief Executive Officer Ian Robertson and other members of the Executive Team to transition into the role of Chief Executive Officer in 2020.

APUC also announced that David Bronicheski, Chief Financial Officer, is retiring in the fall of 2020, and that Arthur Kacprzak, Vice President, Treasury and Treasurer, has been promoted to Senior Vice President and Deputy Chief Financial Officer.

There can be no assurance that leadership transitions will be successful and the transitions may have an adverse impact to APUC and its business.

Mechanical and Operational Risks

APUC's profitability could be impacted by, among other things, equipment failure, the failure of a major customer to fulfill its contractual obligations under its PPA, reductions in average energy prices, a strike or lock-out at a facility, natural disasters, diseases (including the 2019 Novel Coronavirus) and other force majeure events, interruption in supply chain and expenses related to claims or clean-up to adhere to environmental and safety standards.

The Regulated Services Group's water and wastewater distribution systems operate under pressurized conditions within pressure ranges approved by regulators. Should a water distribution network become compromised or damaged, the resulting release of pressure could result in serious injury or death to individuals or damage to other property.

The Regulated Services Group's electric distribution systems are subject to storm events, usually winter storm events, whereby power lines can be brought down, with the attendant risk to individuals and property. In addition, in forested areas, power lines brought down by wind can ignite forest fires which also bring attendant risk to individuals and property.

The Regulated Services Group's natural gas distribution systems are subject to risks which may lead to fire and/or explosion which may impact life and property. Risks include third party damage, compromised system integrity, type/age of pipelines, and severe weather events.

The Renewable Energy Group's hydro assets utilize dams to pond water for generation and if the dams fail/breach potentially catastrophic amounts of water would flood downriver from the facility. The dams can be subjected to drought conditions and lose the ability to generate during peak load conditions, causing the facilities to fall short of either hedged or PPA committed production levels. The risks of the hydro facilities are mitigated by regular dam inspections and a maintenance program of the facility to lessen the risk of dam failure.

The Renewable Energy Group's wind assets could catch on fire and, depending on the season, could ignite significant amounts of forest or crop downwind from the wind farms. The wind units could also be affected by large atmospheric conditions, which will lower wind levels below our PPA and hedge minimum production levels. The wind units can experience failures in the turbine blades or in the supporting towers. Production risks associated with the wind turbine generators failures is mitigated by properly maintaining the units, using long term maintenance agreements with the turbine O&Ms which provide for regular inspections and maintenance of property, and liability insurance policies. Icing can be mitigated by shutting down the unit as icing is detected at the site.

The Renewable Energy Group's Thermal Energy Division uses natural gas and oil, and produces exhaust gases, which if not properly treated and monitored could cause hazardous chemicals to be released into the atmosphere. The units could also be restricted from purchasing gas/oil due to either shortages or pollution levels, which could hamper output of the facility. The mechanical and operational risks at the thermal facilities are mitigated through the regular maintenance of the boiler system, and by continual monitoring of exhaust gases. Fuel restrictions can be hedged in part by long term purchases.

All of the Renewable Energy Group's electric generating stations are subject to mechanical breakdown. The risk of mechanical breakdown is mitigated by properly maintaining the units and by regular inspections.

These risks are mitigated through the diversification of APUC’s operations, both operationally and geographically, the use of regular maintenance programs, including pipeline safety programs and compliance programs, and maintaining adequate insurance, an active Enterprise Risk Management program and the establishment of reserves for expenses.

Regulatory Risk

Profitability of APUC businesses is, in part, dependent on regulatory climates in the jurisdictions in which those businesses operate. In the case of some of Renewable Energy Group's hydroelectric facilities, water rights are generally owned by governments that reserve the right to control water levels, which may affect revenue.

The Regulated Services Group’s facilities are subject to rate setting by state regulatory agencies. The Regulated Services Group operates in 13 different states and 1 province and therefore is subject to regulation from 14 different regulatory agencies. The time between the incurrence of costs and the granting of the rates to recover those costs by state regulatory agencies is known as regulatory lag. As a result of regulatory lag, inflationary effects may impact the ability to recover expenses, and profitability could be impacted. In order to mitigate this exposure, the Regulated Services Group seeks to obtain approval for regulatory constructs in the states in which it operates to allow for timely recovery of operating expenses. A fundamental risk faced by any regulated utility is the disallowance of costs to be placed into its revenue requirement by the utility's regulator. To the extent proposed costs are not allowed into rates, the utility will be required to find other efficiencies or cost savings to achieve its allowed returns.

The Regulated Services Group regularly works with its governing authorities to manage the affairs of the business, employing both local, state level, and corporate resources.

On December 22, 2017, the Tax Cuts and Jobs Act was signed into law which resulted in significant changes to U.S. tax law. Amongst other things, the Act reduced the federal corporate income tax rates from 35% to 21%. The change in corporate tax rates has had an impact on regulatory revenue requirements of most public utilities, including the Regulated Services Group. The Regulated Services Group obtained orders from the majority of its principal regulators, resulting in the reduction of customer rates in connection with the reduction in tax rates. Since the Company has not yet received rate orders addressing all matters related to U.S. Tax Reform for all of its utilities, the full impact of rate reductions related to U.S. Tax Reform is not known.

Condemnation Expropriation Proceedings

The Regulated Services Group's distribution systems could be subject to condemnation or other methods of taking by government entities under certain conditions. Any taking by government entities would legally require fair compensation to be paid. Determination of such fair compensation is undertaken pursuant to a legal proceeding and, therefore, there is no assurance that the value received for assets taken will be in excess of book value.

Apple Valley Condemnation Proceedings

On January 7, 2016, the Town of Apple Valley filed a lawsuit seeking to condemn the utility assets of the Regulated Services Group (Apple Valley Ranchos Water) Corp ("Liberty Apple Valley"). The lawsuit will be adjudicated in phases. In the first phase, the Court will determine whether to allow the taking by the Town; under California law, the taking will be allowed unless Liberty Apple Valley proves there is not a "public necessity" for the taking. If Liberty Apple Valley prevails, the case is concluded and the Town will be required to compensate Liberty Apple Valley for its litigation expenses. However, if the Court determines that the taking is allowed, there will be a second phase of the trial in which a jury will determine the amount of compensation owed for the taking based upon the fair market value of the assets being condemned. The right to take trial began on October 23, 2019, and is expected to continue until March 2020 with a judicial decision on the right to take expected in the third quarter of 2020. If, following that trial, there is a need for a second phase to determine compensation, that trial can be expected to occur six to twelve months after the conclusion of the first phase.

Acquisition Risk

Part of the Company's business strategy is to acquire new generating stations and existing regulated utilities. The Company's acquisition strategy introduces exposures inherent to such transactions that may adversely affect the results of an acquisition, including failure to obtain required approvals, delays in implementation or unexpected costs or liabilities, as well as the risk of failing to realize operating benefits or synergies. The Company mitigates these risks by following systematic procedures for integrating acquisitions, applying strict financial metrics to any potential acquisition and subjecting the process to close monitoring and review by the Board of Directors.

When acquisitions occur, significant demands can be placed on the Company's managerial, operational and financial personnel and systems. No assurance can be given that the Company's systems, procedures and controls will be adequate to support the expansion of the Company's operations resulting from the acquisition. The Company's future operating results will be affected by the ability of its officers and key employees to manage changing business conditions and to implement and improve its operational and financial controls and reporting systems.

The Company's growth strategy may be constrained by factors associated with the maintenance of its BBB flat investment grade credit ratings. These factors include: (i) constraints on maximum leverage, (ii) the proportion of EBITDA (as determined by applicable rating agency methodologies) required to be generated from the Regulated Services Group, and (iii) the geographies in which APUC can operate in scale. There can be no assurance that these constraints will not negatively impact the Company's ability to successfully execute on available growth opportunities. The business mix target may from time to time require APUC to grow its Regulated Services Group or implement other strategies in order to pursue investment opportunities within its Renewable Energy Group.

International Investment Risk

The Company's investment in Atlantica exposes the Company to certain risks that are particular to Atlantica's business and the markets in which Atlantica operates.

Atlantica owns, manages and acquires renewable energy, conventional power, electric transmission lines and water assets in certain jurisdictions where the Company may not operate. The Company, through its investment in Atlantica, is indirectly exposed to certain risks that are particular to the markets in which it operates, including, but not limited to, risks related to: conditions in the global economy; changes to national and international laws, political, social and macroeconomic risks relating to the jurisdictions in which Atlantica operates, including in emerging markets, which could be subject to economic, social and political uncertainties; anti-bribery and anti-corruption laws and substantial penalties and reputational damage from any non-compliance therewith; significant currency exchange rate fluctuations; Atlantica's ability to identify and/or consummate future acquisitions on favourable terms or at all; Atlantica's inability to replace, on similar or commercially favourable terms, expiring or terminated offtake agreements; termination or revocation of Atlantica's concession agreements or PPAs; and various other factors. These risks could affect the profitability and growth of Atlantica's business, and ultimately the profitability of the Company's anticipated investment therein.

The Company's international acquisition, development, construction and operating activities, including through the AAGES joint venture, expose the Company to similar risks and could likewise affect the profitability, financial condition and growth of the Company.

Risks Specific to the Atlantica Investment

The Company accounts for its investment in Atlantica using the Fair Value Method (see *Note 1(n)* in the audited consolidated financial statements). APUC records in the consolidated statements of operations the fluctuations in the fair value of Atlantica shares and dividend income when it is declared. During 2019, Atlantica announced it is undertaking a strategic review process. The results of this process have not yet been announced and the outcome is uncertain. Atlantica's share price may be adversely affected by the outcome of the strategic review, which would in turn could negatively affect APUC's results.

Joint Venture Investment Risk

The Company has, and in the future may continue to have, an interest in projects over which it does not have sole control, which may create a risk that the Company's joint venture partner may:

- have economic or business interests or goals that are inconsistent with the Company's economic or business interests or goals;
- take actions contrary to the Company's policies or objectives with respect to the Company's investments;
- contravene applicable anti-bribery laws that carry substantial penalties for non-compliance and could cause reputational damage and a material adverse effect on the business, financial position and results of operations of the joint venture and the Company;
- have to give its consent with respect to certain major decisions, including among others, decisions relating to funding and transactions with affiliates;
- become bankrupt, limiting its ability to meet calls for capital contributions and potentially making it more difficult to refinance or sell projects;
- become engaged in a dispute with the Company that might affect the Company's ability to develop a project; or
- have competing interests in the Company's markets that could create conflict of interest issues.

The Company's involvement with AAGES may also present a reputational risk, including from the reputation of Abengoa. AAGES has obtained a 3 year secured credit facility in the amount of $306.5 million ("AAGES Credit Facility"), which is collateralized through a pledge of the Atlantica shares. A collateral shortfall would occur if the net obligation as defined in the agreement would equal or exceed 50% of the market value of the Atlantica shares. In the event of a collateral shortfall AAGES is required to post additional collateral in cash to reduce the net obligation to 40% of the total collateral provided ("Collateral Reset Level"). If AAGES were unable to fund the collateral shortfall, the AAGES Credit Facility lenders hold the right to sell Atlantica stock to reduce the facility to the Collateral Reset Level. The AAGES Credit Facility is repayable on demand if Atlantica ceases to be a public company. If AAGES were unable to repay the amounts owed, the lenders would have the right realize on their collateral.

The Company has entered into Equity Capital Contribution Agreements ("ECCA") with certain of its project development entities it holds an equity interest in. The ECCAs obligate the Company to provide funding upon the realization of certain completion milestones related to the projects under development. The ECCAs have been pledged as collateral against construction loans obtained by the project entities and may require the Company to fund in amounts in excess of the underlying value of the assets. The Company has also provided guarantees of performance for certain development projects owned by the equity investees.

Please refer to *Note 8* in the annual audited consolidated financial statements for a description of the Company's Long Term Investments and Notes Receivable.

Asset Retirement Obligations

APUC and its subsidiaries complete periodic reviews of potential asset retirement obligations that may require recognition. As part of this process, APUC and its subsidiaries consider the contractual requirements outlined in their operating permits, leases, and other agreements, the probability of the agreements being extended, the ability to quantify such expense, the timing of incurring the potential expenses, as well as other factors which may be considered in evaluating if such obligations exist and in estimating the fair value of such obligations.

In conjunction with acquisitions and developed projects, the Company assumed certain asset retirement obligations. The asset retirement obligations mainly relate to legal requirements for: (i) removal or decommissioning of power generating facilities; (ii) cut (disconnect from the distribution system), purge (clean of natural gas and PCB contaminants), and cap gas mains within the gas distribution and transmission system when mains are retired in place, or dispose of sections of gas mains when removed from the pipeline system; (iii) clean and remove storage tanks containing waste oil and other waste contaminants; and (iv) remove asbestos upon major renovation or demolition of structures and facilities.

Cycles and Seasonality

Regulated Services Group

The Regulated Services Group's demand for water is affected by weather conditions and temperature. Demand for water during warmer months is generally greater than cooler months due to requirements for irrigation, swimming pools, cooling systems and other outside water use. If there is above normal rainfall or rainfall is more frequent than normal the demand for water may decrease, adversely affecting revenues.

The Regulated Services Group's demand for energy from its electric distribution systems is primarily affected by weather conditions and conservation initiatives. The Regulated Services Group provides information and programs to its customers to encourage the conservation of energy. In turn, demand may be reduced which could have short term adverse impacts on revenues.

The Regulated Services Group's primary demand for natural gas from its natural gas distribution systems is driven by the seasonal heating requirements of its residential, commercial, and industrial customers. The colder the weather the greater the demand for natural gas to heat homes and businesses. As such, the natural gas distribution systems demand profiles typically peaks in the winter months of January and February and declines in the summer months of July and August. Year to year variability also occurs depending on how cold the weather is in any particular year.

The Company attempts to mitigate the above noted risks by seeking regulatory mechanisms during rate review proceedings. While not all regulatory jurisdictions have approved mechanisms to mitigate demand fluctuations, to date, the Regulated Services Group has successfully obtained regulatory approval to implement such decoupling mechanisms in 7 of 13 states. An example of such a mechanism is seen at the Peach State Gas System in Georgia, where a weather normalization adjustment is applied to customer bills during the months of October through May that adjusts commodity rates to stabilize the revenues of the utility for changes in billing units attributable to weather patterns.

Renewable Energy Group

The Renewable Energy Group's hydroelectric operations are impacted by seasonal fluctuations and year to year variability of the available hydrology. These assets are primarily “run-of-river” and as such fluctuate with natural water flows. During the winter and summer periods, flows are generally lower while during the spring and fall periods flows are generally higher. The ability of these assets to generate income may be impacted by changes in water availability or other material hydrologic events within a watercourse. Year to year the level of hydrology varies, impacting the amount of power that can be generated in a year.

The Renewable Energy Group's wind generation facilities are impacted by seasonal fluctuations and year to year variability of the wind resource. During the fall through spring period, winds are generally stronger than during the summer periods. The ability of these facilities to generate income may be impacted by naturally occurring changes in wind patterns and wind strength.

The Renewable Energy Group's solar generation facilities are impacted by seasonal fluctuations and year to year variability in the solar radiance. For instance, there are more daylight hours in the summer than there are in the winter, resulting in higher production in the summer months. The ability of these facilities to generate income may be impacted by naturally occurring changes in solar radiance.

The Company attempts to mitigate the above noted natural resource fluctuation risks by acquiring or developing generating stations in different geographic locations.

Development and Construction Risk

The Company actively engages in the development and construction of new power generation facilities. There is always a risk that material delays and/or cost overruns could be incurred in any of the projects planned or currently in construction affecting the Company’s overall performance. There are risks that actual costs may exceed budget estimates, delays may occur in obtaining permits and materials, suppliers and contractors may not perform as required under their contracts, there may be inadequate availability, productivity or increased cost of qualified craft labor, start-up activities may take longer than planned, the scope and timing of projects may change, and other events beyond the Company's control may occur that may materially affect the schedule, budget, cost and performance of projects. Regulatory approvals can be challenged by a number of mechanisms which vary across state and provincial jurisdictions. Such permitting challenges could identify issues that may result in permits being modified or revoked.

Risks Specific to Renewable Generation Projects:

The strength and consistency of the wind resource will vary from the estimate set out in the initial wind studies that were relied upon to determine the feasibility of the wind facility. If weather patterns change or the historical data proves not to accurately reflect the strength and consistency of the actual wind, the assumptions underlying the financial projections as to the amount of electricity to be generated by the facility may be different and cash could be impacted.

The amount of solar radiance will vary from the estimate set out in the initial solar studies that were relied upon to determine the feasibility of the solar facility. If weather patterns change or the historical data proves not to accurately reflect the strength and consistency of the solar radiance, the assumptions underlying the financial projections as to the amount of electricity to be generated by the facility may be different and cash could be impacted.

For certain of its development projects, the Company relies on financing from third party tax equity investors. These investors typically provide funding upon commercial operation of the facility. Should certain facilities not meet the conditions required for tax equity funding, expected returns from the facilities may be impacted.

Development by the Renewable Energy Group of renewable power generation facilities in the United States depends in part on federal tax credits and other tax incentives. These incentives are currently subject to a multi-year step-down. The first step down occurs on December 31, 2020. APUC currently has a number of significant projects in construction that could be materially adversely affected if they are not placed in service by this date.

In February 2020, APUC received force majeure notices from certain of its turbine suppliers related to the 2019 Novel Coronavirus outbreak. The notices relate to wind energy projects from both the Regulated Services Group and Renewable Energy Group and a solar project from the Renewable Energy Group. While the exact impacts of the 2019 Novel Coronavirus outbreak on APUC and its projects remain unknown, manufacturing and delivery delays caused by the 2019 Novel Coronavirus could adversely affect its projects, including (a) causing one or more projects scheduled for completion in 2020 to not be placed in service until 2021 or (b) adversely impacting the availability of tax equity or other financing. APUC is working with its suppliers, contractors and advisors in an effort to mitigate the impacts on its projects, but there can be no assurance that such efforts will be successful.

Litigation Risks and Other Contingencies

APUC and certain of its subsidiaries are involved in various litigation, claims and other legal and regulatory proceedings that arise from time to time in the ordinary course of business. Any accruals for contingencies related to these items are recorded in the financial statements at the time it is concluded that a material financial loss is likely and the related liability is estimable. Anticipated recoveries under existing insurance policies are recorded when reasonably assured of recovery.

Claim by Gaia Power Inc.

On October 30, 2018, Gaia Power Inc. ("Gaia") commenced an action in the Ontario Superior Court of Justice against APUC and certain of its subsidiaries, claiming damages of not less than C$345 million and punitive damages in the sum of C$25 million. The action arises from Gaia's 2010 sale, to a subsidiary of APUC, of Gaia's interest in certain proposed wind farm projects in Canada. Pursuant to a 2010 royalty agreement, Gaia is entitled to royalty payments if the projects are developed and achieve certain agreed targets.

The parties have since agreed to arbitrate the matter pursuant to the royalty agreement's arbitration clause. APUC and the other respondents have delivered their responses to Gaia's notice of arbitration, and the parties are currently in the process of exchanging documentary productions. It is too early to determine the likelihood of success in this lawsuit, however APUC intends to vigorously defend it.

Information Security Risk

The Company's information technology systems may be vulnerable to potential risks from cybersecurity attacks. Attacks can be caused by malware, viruses, email attachments, acts of war or terrorism and can originate from individuals from both inside and outside the organization. An attack could result in service disruptions, system failures, the disclosure of personal customer and employee information, and could lead to an adverse effect on the Company's financial performance. A breach of personal or confidential information may also occur as a result of non-cyber means, such as breach of physical security and device theft. Should a material breach occur the Company may not be able to recover all costs and losses through insurance, legal or regulatory processes.

Energy Consumption and Advancement in Technologies Risk

The Regulated Services Group's operations are subject to changes in demand for energy which are impacted by general economic conditions, customer's focus on energy efficiency, and advancements in new technologies.

The Regulated Services Group is actively involved in working with governments and customers to ensure these changes in consumption do not negatively impact the services provided. Furthermore, through its strategic initiatives the Regulated Services Group is constantly looking for ways to maintain the Company's competitive advantage.

Uninsured Risk

The Company maintains insurance for accidental loss and potential liabilities to third parties in accordance with the industry practice. However, there are certain elements of the Regulated Services Group's regulated utilities that are not fully insured as the cost of the coverage is not economically viable. In the event that a liability event or loss is not covered through insurance the Regulated Services Group would apply to their respective regulator to request recovery through increased customer rates. Cost recovery through this mechanism is subject to regulatory approval and is therefore uncertain.

Insurance coverage for the rest of the Company is also subject to policy conditions and exclusions, coverage limits, and various deductibles, and not all types of liabilities and losses may be covered by insurance, in which case the Company may be financially exposed.

QUARTERLY FINANCIAL INFORMATION

The following is a summary of unaudited quarterly financial information for the eight quarters ended December 31, 2019:

(all dollar amounts in $ millions except per share information)	1st Quarter 2019	2nd Quarter 2019	3rd Quarter 2019	4th Quarter 2019
Revenue	$ 477.2	$ 343.6	$ 364.4	$ 439.7
Net earnings attributable to shareholders	86.4	156.6	115.8	172.1
Net earnings per share	0.17	0.31	0.23	0.34
Diluted net earnings per share	0.17	0.31	0.23	0.33
Adjusted Net Earnings[1]	93.8	54.9	69.0	103.6
Adjusted Net Earnings per share[1]	0.19	0.11	0.14	0.20
Adjusted EBITDA[1]	231.5	189.8	185.8	231.5
Total assets	9,671.3	10,034.3	10,618.9	10,911.5
Long term debt[2]	3,651.9	3,782.3	4,276.6	3,932.2
Dividend declared per common share	$ 0.13	$ 0.14	$ 0.14	$ 0.14

	1st Quarter 2018	2nd Quarter 2018	3rd Quarter 2018	4th Quarter 2018
Revenue	$ 494.8	$ 366.2	$ 365.6	$ 421.9
Net earnings attributable to shareholders	17.6	65.5	57.9	44.0
Net earnings per share	0.04	0.14	0.12	0.09
Diluted net earnings per share	0.04	0.14	0.12	0.09
Adjusted Net Earnings[1]	141.1	50.9	49.7	70.5
Adjusted Net Earnings per share[1]	0.30	0.11	0.10	0.14
Adjusted EBITDA[1]	279.2	160.3	166.0	198.9
Total assets	8,941.8	8,920.7	9,072.6	9,398.6
Long term debt[2]	3,832.7	3,448.1	3,561.3	3,337.3
Dividend declared per common share	$ 0.12	$ 0.13	$ 0.13	$ 0.13

1 See *Non-GAAP Financial Measures*

2 Includes current portion of long-term debt, long-term debt and convertible debentures.

The quarterly results are impacted by various factors including seasonal fluctuations and acquisitions of facilities as noted in this MD&A.

Quarterly revenues have fluctuated between $343.6 million and $494.8 million over the prior two year period. A number of factors impact quarterly results including acquisitions, seasonal fluctuations, and winter and summer rates built into the PPAs.

In addition, a factor impacting revenues year over year is the fluctuation in the strength of the Canadian dollar relative to the U.S. dollar which can result in significant changes in reported revenue from Canadian operations.

Quarterly net earnings attributable to shareholders have fluctuated between $17.6 million and $172.1 million over the prior two year period. Earnings have been significantly impacted by non-cash factors such as deferred tax recovery and expense, impairment of intangibles, property, plant and equipment and mark-to-market gains and losses on financial instruments.

SUMMARY FINANCIAL INFORMATION OF ATLANTICA

The Company owns a 44.2% beneficial stake in Atlantica. APUC accounts for its interest in Atlantica using the fair value method (see *Note 8(a)* in the annual audited consolidated financial statements). The summary financial information of Atlantica in the following table is derived from the audited consolidated financial statements of Atlantica as of December 31, 2019 and 2018 and for the years then ended which are reported in U.S. dollars and were prepared using International Financial Reporting Standards, as issued by the International Accounting Standards Board ("IFRS"). The recognition, measurement and disclosure requirements of IFRS differ from U.S. GAAP as applied by the Company.

(all dollar amounts in $ millions)	2019	2018
Revenue	**$ 1,011.5**	$ 1,043.8
Profit (loss) for the year	**74.6**	55.3
Total non-current assets	**8,540.6**	8,791.3
Total current assets	**1,119.2**	1,127.7
Total non-current liabilities	**6,971.6**	7,423.8
Total current liabilities	**973.4**	739.1

DISCLOSURE CONTROLS AND PROCEDURES

APUC's management carried out an evaluation as of December 31, 2019, under the supervision of and with the participation of APUC's Chief Executive Officer ("CEO") and Chief Financial Officer ("CFO"), of the effectiveness of the design and operations of APUC's disclosure controls and procedures (as defined in Rule 13a-15(e) and Rule 15d-15 (e) under the Securities Exchange Act of 1934, as amended (the "Exchange Act")). Based on that evaluation, the CEO and the CFO have concluded that as of December 31, 2019, APUC's disclosure controls and procedures are effective to provide reasonable assurance that information required to be disclosed by APUC in reports that it files or submits under the Exchange Act is recorded, processed, summarized, and reported within the time periods specified in SEC rules and forms, and is accumulated and communicated to management, including the CEO and CFO, as appropriate, to allow timely decisions regarding required disclosure.

MANAGEMENT REPORT ON INTERNAL CONTROLS OVER FINANCIAL REPORTING

Management, including the CEO and the CFO, is responsible for establishing and maintaining internal control over financial reporting (as defined in Rules 13a-15(f) under the Exchange Act) to provide reasonable, but not absolute, assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with U.S. GAAP.

The Company's internal control over financial reporting framework includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the Company, (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with U.S. GAAP, and that receipts and expenditures of the Company are being made only in accordance with authorizations of management and directors of the Company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of the Company's assets that could have a material effect on the Company's consolidated financial statements.

Due to its inherit limitations, disclosure controls and procedures or internal control over financial reporting may not prevent or detect all misstatements based on error of fraud. Further, the effectiveness of internal control is subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with policies or procedures may change.

During the year ended December 31, 2019, the Company acquired St. Lawrence Gas and New Brunswick Gas. Management is in the process of evaluating the existing controls and procedures of St. Lawrence Gas and New Brunswick Gas and integrating financial reporting and controls for St. Lawrence Gas and New Brunswick Gas into the Company's internal control over financial reporting. The financial information for these acquisitions is included in this MD&A and in *Note 3* in the annual audited consolidated financial statements. As permitted under applicable laws due to the complexity associated with assessing internal controls during integration efforts, the Company excluded these acquisitions from its evaluation of the effectiveness of the

Company's internal controls over financial reporting as of December 31, 2019 (representing approximately 4% of our total assets as of December 31, 2019 and approximately 2% of our revenues for the year ended December 31, 2019). Management assessed the effectiveness of the Company's internal control over financial reporting as of December 31, 2019, based on the framework established in Internal Control - Integrated Framework (2013) issued by COSO. This assessment included review of the documentation of controls, evaluation of the design effectiveness of controls, testing of the operating effectiveness of controls, and a conclusion on this evaluation. Based on this assessment, management concluded that the Company's internal control over financial reporting was effective as of December 31, 2019 to provide reasonable assurance regarding the reliability of financial reporting and the preparation of consolidated financial statements for external reporting purposes in accordance with U.S. GAAP. Management reviewed the results of its assessment with the Audit Committee of the Board of Directors of APUC.

CHANGES IN INTERNAL CONTROLS OVER FINANCIAL REPORTING

For the twelve months ended December 31, 2019, there has been no change in the Company's internal controls over financial reporting that has materially affected, or is reasonably likely to materially affect, the Company's internal controls over financial reporting.

INHERENT LIMITATIONS ON EFFECTIVENESS OF CONTROLS

Due to its inherent limitations, disclosure controls and procedures or internal control over financial reporting may not prevent or detect all misstatements based on error of fraud. Further, the effectiveness of internal control is subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with policies or procedures may change.

CRITICAL ACCOUNTING ESTIMATES AND POLICIES

APUC prepared its consolidated financial statements in accordance with U.S. GAAP. The preparation of consolidated financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, related amounts of revenues and expenses, and disclosure of contingent assets and liabilities. Significant areas requiring the use of management judgment relate to the scope of consolidated entities, useful lives and recoverability of depreciable assets, the measurement of deferred taxes and the recoverability of deferred tax assets, rate-regulation, unbilled revenue, pension and post-employment benefits, fair value of derivatives and fair value of assets and liabilities acquired in a business combination. Actual results may differ from these estimates.

APUC's significant accounting policies and new accounting standards are discussed in *Notes 1 and 2* in the annual audited consolidated financial statements, respectively. Management believes the following accounting policies involve the application of critical accounting estimates. Accordingly, these accounting estimates have been reviewed and discussed with the Audit Committee of the Board of Directors of APUC.

Consolidation and Variable Interest Entities

The Company uses judgment to assess whether its operations or investments represent variable interest entities ("VIEs"). In making these evaluations, management considers a) the sufficiency of the investment's equity at risk, b) the existence of a controlling financial interest, and c) the structure of any voting rights. In addition, management considers the specific facts and circumstances of each investment in a VIE when determining whether the Company is the primary beneficiary. The factors that management takes into consideration include the purpose and design of the VIE, the key decisions that affect its economic performance, whether the parties to the arrangements are related parties or defacto agents of the Company, and whether the Company has the power to direct the activities that would most significantly affect the economic performance of the VIE. Management's judgment is also required to determine whether the Company has the right to receive benefits or the obligation to absorb losses of the VIE. Based on the judgments made, the Company will consolidate the VIE if it determines that it is the primary beneficiary.

Estimated Useful Lives and Recoverability of Long-Lived Assets, Intangibles and Goodwill

The Company makes judgments a) to determine the recoverability of a development project, and the period over which the costs are capitalized during the development and construction of the project, b) to assess the nature of the costs to be capitalized, c) to distinguish individual components and major overhauls, and d) to determine the useful lives or unit-of-production over which assets are depreciated.

Depreciation rates on utility assets are subject to regulatory review and approval, and depreciation expense is recovered through rates set by ratemaking authorities. The recovery of those costs is dependent on the ratemaking process.

The carrying value of long-lived assets, including intangible assets and goodwill, is reviewed whenever events or changes in circumstances indicate that such carrying values may not be recoverable, and at least annually for goodwill. Some of the factors APUC considers as indicators of impairment include a significant change in operational or financial performance, unexpected outcome from rate orders, natural disasters, energy pricing and changes in regulation. When such events or circumstances are present, the Company assesses whether the carrying value will be recovered through the expected future cash flows. If the facility includes goodwill, the fair value of the facility is compared to its carrying value. Both methodologies are sensitive to the forecasted cash flows and in particular energy prices, long-term growth rate and, discount rate for the fair value calculation.

In 2019 and 2018, Management assessed qualitative and quantitative factors for each of the reporting units that were allocated goodwill. No goodwill impairment provision was required.

Valuation of Deferred Tax Assets

In assessing the realization of deferred tax assets, management considers whether it is more likely than not that some portion or all of the deferred tax assets will not be realized and provides any necessary valuation allowances as required. Management evaluates the probability of realizing deferred tax assets by reviewing a forecast of future taxable income together with Management's intent and ability to implement tax planning strategies, if necessary, to realize deferred tax assets. Although at this time Management considers it more likely than not that it will have sufficient taxable income to realize the deferred tax assets, there can be no assurance that the Company will generate sufficient taxable income in the future to utilize these deferred tax assets. Management also assesses the ability to utilize tax attributes, including those in the form of carryforwards, for which the benefits have already been reflected in the financial statements.

Accounting for Rate Regulation

Accounting guidance for regulated operations provides that rate-regulated entities account for and report assets and liabilities consistent with the recovery of those incurred costs in rates if the rates established are designed to recover the costs of providing the regulated service and if the competitive environment makes it probable that such rates can be charged and collected. This accounting guidance is applied to the Regulated Services Group's operations.

Certain expenses and revenues subject to utility regulation or rate determination normally reflected in income are deferred on the balance sheet as regulatory assets or liabilities and are recognized in income as the related amounts are included in service rates and recovered from or refunded to customers. Regulatory assets and liabilities are recorded when it is probable that these items will be recovered or reflected in future rates. Determining probability requires significant judgment on the part of management and includes, but is not limited to, consideration of testimony presented in regulatory hearings, proposed regulatory decisions, final regulatory orders and industry practice. If events were to occur that would make the recovery of these assets and liabilities no longer probable, these regulatory assets and liabilities would be required to be written off or written down.

Unbilled Energy Revenues

Revenues related to natural gas, electricity and water delivery are generally recognized upon delivery to customers. The determination of customer billings is based on a systematic reading of meters throughout the month. At the end of each month, amounts of natural gas, energy or water provided to customers since the date of the last meter reading are estimated, and the corresponding unbilled revenue is recorded. Factors that can impact the estimate of unbilled energy include, but are not limited to, seasonal weather patterns compared to normal, total volumes supplied to the system, line losses, economic impacts, and composition of customer classes. Estimates are reversed in the following month and actual revenue is recorded based on subsequent meter readings.

Derivatives

APUC uses derivative instruments to manage exposure to changes in commodity prices, foreign exchange rates, and interest rates. Management's judgment is required to determine if a transaction meets the definition of a derivative and, if it does, whether the normal purchases and sales exception applies or whether individual transactions qualify for hedge accounting treatment. Management's judgment is also required to determine the fair value of derivative transactions. APUC determines the fair value of derivative instruments based on forward market prices in active markets obtained from external parties adjusted for nonperformance risk. A significant change in estimate could affect APUC's results of operations if the hedging relationship was considered no longer effective.

Pension and Post-employment Benefits

The obligations and related costs of defined benefit pension and post-employment benefit plans are calculated using actuarial concepts, which include critical assumptions related to the discount rate, mortality rate, compensation increase, expected rate of return on plan assets and medical cost trend rates. These assumptions are important elements of expense and/or liability measurement and are updated on an annual basis, or upon the occurrence of significant events. The Company used the new mortality improvement scale (MP-2019) recently released by the Society of Actuaries adjusted to reflect the 2019 Social Security Administration ultimate improvement rates.

Sensitivities

The sensitivities of key assumptions used in measuring accrued benefit obligations and benefit plan cost for 2019 are outlined in the following table. They are calculated independently of each other. Actual experience may result in changes in a number of assumptions simultaneously. The types of assumptions and method used to prepare the sensitivity analysis has not changed from previous periods and is consistent with the calculation of the retirement benefit obligations and net benefit plan cost recognized in the consolidated financial statements.

	2019 Pension Plans		2019 OPEB Plans	
(all dollar amounts in $ millions)	Accrued Benefit Obligation	Net Periodic Pension Cost	Accumulated Postretirement Benefit Obligation	Net Periodic Postretirement Benefit Cost
Discount Rate				
1% increase	(54.7)	(2.8)	(32.4)	(1.6)
1% decrease	67.6	5.2	42.0	2.8
Future compensation rate				
1% increase	0.3	1.8	—	—
1% decrease	(0.3)	(3.1)	—	—
Expected return on plan assets				
1% increase	—	(3.3)	—	(1.2)
1% decrease	—	3.3	—	1.2
Life expectancy				
10% increase	32.8	3.6	20.3	2.4
10% decrease	(34.4)	(4.3)	(19.4)	(2.0)
Health care trend				
1% increase	—	—	39.2	4.4
1% decrease	—	—	(30.8)	(2.6)

Business Combinations

The Company has completed a number of business combinations in the past few years. Management's judgment is required to estimate the purchase price, to identify and to fair value all assets and liabilities acquired. The determination of the fair value of assets and liabilities acquired is based upon management's estimates and certain assumptions generally included in a present value calculation of the related cash flows.

Acquired assets and liabilities assumed that are subject to critical estimates include regulated property, plant and equipment, regulatory assets and liabilities, long-term debt and pension and OPEB obligations. The fair value of regulated property, plant and equipment is assessed using an income approach where the estimated cash flows of the assets are calculated using the approved tariff and discounted at the approved rate of return. The fair value of regulatory assets and liabilities considers the estimated timing of the recovery or refund to customers through the rate making process. The fair value of long-term debt is determined using a discounted cash flow method and current interest rates. The pension and OPEB obligations are valued by external actuaries using the guidelines of ASC 805, Business combinations.

Additional disclosure of APUC's critical accounting estimates is also available on SEDAR at www.sedar.com, on EDGAR at www.sec.gov/edgar, and on the APUC website at www.AlgonquinPowerandUtilities.com.

Exhibit 99.4

Consent of Independent Registered Public Accounting Firm

We consent to the reference to our Firm under the caption “Experts”, and to the incorporation by reference in the following Registration Statements:

1. Form S-8 nos. 333-232012, 333-177418, 333-213648, 333-213650, and 333-218810;
2. Form F-10 nos. 333-216616 and 333-227245;
3. Form F-3 nos. 333-220059 and 333-227246

of Algonquin Power and Utilities Corp. (the “Company”) and the use herein of our reports dated February 27, 2020, with respect to the consolidated balance sheets as of December 31, 2019 and December 31, 2018 and the consolidated statements of operations, comprehensive income, equity and cash flows for each of the years in the two-year period ended December 31, 2019, and the effectiveness of internal control over financial reporting of the Company as of December 31, 2019, included in this Annual Report on Form 40-F.

/s/ Ernst & Young LLP
Chartered Professional Accountants,
Licensed Public Accountants

Toronto, Canada
February 27, 2020

Exhibit 99.5

CERTIFICATION PURSUANT TO SECTION 302 OF THE U.S. SARBANES-OXLEY ACT OF 2002

I, Ian E. Robertson, certify that:

1. I have reviewed this annual report on Form 40-F of Algonquin Power & Utilities Corp.

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the issuer as of, and for, the periods presented in this report;

4. The issuer's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the issuer and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the issuer, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the issuer's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the issuer's internal control over financial reporting that occurred during the period covered by the annual report that has materially affected, or is reasonably likely to materially affect, the issuer's internal control over financial reporting; and

5. The issuer's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the issuer's auditors and the audit committee of the issuer's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the issuer's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the issuer's internal control over financial reporting.

Date: February 27, 2020

By:	/s/ Ian E. Robertson
Name:	Ian E. Robertson
Title:	Chief Executive Officer

Exhibit 99.6

CERTIFICATION PURSUANT TO SECTION 302 OF THE U.S. SARBANES-OXLEY ACT OF 2002

I, David Bronicheski, certify that:

1. I have reviewed this annual report on Form 40-F of Algonquin Power & Utilities Corp.

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the issuer as of, and for, the periods presented in this report;

4. The issuer's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the issuer and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the issuer, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the issuer's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the issuer's internal control over financial reporting that occurred during the period covered by the annual report that has materially affected, or is reasonably likely to materially affect, the issuer's internal control over financial reporting; and

5. The issuer's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the issuer's auditors and the audit committee of the issuer's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the issuer's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the issuer's internal control over financial reporting.

Date: February 27, 2020

By:	/s/ David Bronicheski
Name:	David Bronicheski
Title:	Chief Financial Officer

Exhibit 99.7

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of Algonquin Power & Utilities Corp. (the “Corporation”) on Form 40-F for the year ended December 31, 2019 as filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, Ian E. Robertson, Chief Executive Officer of the Corporation, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to my knowledge:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Corporation.

Date: February 27, 2020	By:	/s/ Ian Robertson
	Name:	Ian E. Robertson
	Title:	Chief Executive Officer

Exhibit 99.8

**CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002**

In connection with the Annual Report of Algonquin Power & Utilities Corp. (the "Corporation") on Form 40-F for the year ended December 31, 2019 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, David Bronicheski, Chief Financial Officer of the Corporation, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to my knowledge:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Corporation.

Date: February 27, 2020	By:	/s/ David Bronicheski
	Name:	David Bronicheski
	Title:	Chief Financial Officer