UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 40 F

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

OR

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

For the fiscal year ended December 31, 2017 **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	**Name of each exchange on which registered**
Common shares, no par value	Toronto Stock Exchange
	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:

x **Annual Information Form** x **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, 2017, there were 431,765,935 Common Shares outstanding.

Indicate by check mark whether the Registrant by filing the information contained in this Form is also thereby furnishing the information to the Commission pursuant to Rule 12g3-2(b) under the Securities Exchange Act of 1934 (the "Exchange Act"). If "Yes" is marked, indicate the file number assigned to the Registrant in connection with such Rule.

Yes o **No** x

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 x **No** o

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 o

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. o

Indicate by check mark whether the Registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this Chapter) during the preceding 12 months (or for such shorter period that the Registrant was required to submit and post such files).

Yes x **No** o

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 No. 333-220059), F-10 (File No. 333-216616) and Form F-8 (File Nos. 333-177418, 333-213648, 333-213650 and 333-218810) and under the Securities Act of 1933, as amended.

ANNUAL INFORMATION FORM

The Annual Information Form of Algonquin Power & Utilities Corp. ("Algonquin") for the fiscal year ended December 31, 2017 is filed as Exhibit 99.1 to this annual report on Form 40-F.

AUDITED ANNUAL FINANCIAL STATEMENTS

The Audited Annual Financial Statements of Algonquin for the fiscal year ended December 31, 2017 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, 2017 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” (page 56) in the Management’s Discussion and Analysis for the fiscal year ended December 31, 2017 (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

Management, including the 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.

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 US 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, 2017, the Company acquired The Empire District Electric Company (“Empire”). Management is in the process of evaluating the existing controls and procedures of Empire and integrating financial reporting and controls for Empire into the Company’s internal control over financial reporting. The financial information for this acquisition is included in the 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, the Company excluded this acquisition from its assessment of the effectiveness of the Company's internal controls over financial reporting (representing approximately 30% of our total assets as of December 31, 2017 and 41% of our revenues and 35% of our net income for the year ended December 31, 2017).

Management assessed the effectiveness of Algonquin’s internal control over financial reporting as of December 31, 2017, 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 Algonquin’s internal control over financial reporting was effective as of December 31, 2017 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 Algonquin, which audited the consolidated financial statements of Algonquin for the year ended December 31, 2017, has also issued an attestation report on the effectiveness of Algonquin's internal control over financial reporting as of December 31, 2017. The attestation report is provided in Exhibit 99.2 to this annual report on Form 40-F.

C. Changes in internal control over financial reporting

The information provided under the heading "Changes in Internal Controls Over Financial Reporting" (page 56) in the Management's Discussion and Analysis for the fiscal year ended December 31, 2017, filed as Exhibit 99.3 to this annual report on Form 40-F, is incorporated by reference herein.

AUDIT COMMITTEE FINANCIAL EXPERTS

Algonquin'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 that term is defined by the Toronto Stock Exchange's listing standards applicable to Algonquin and Rule 10A-3 of the Exchange Act. The SEC has indicated that the designation of Christopher Ball and Dilek Samil as audit committee financial experts does not make either of them an "expert" for any purpose, impose any duties, obligations or liability on Christopher Ball and Dilek Samil 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

Algonquin 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 Ian Tharp, Telephone: (905) 465-4500, E-mail: ir@algonquinpower.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" (page 61) in the Annual Information Form for the fiscal year ended December 31, 2017, 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, 2016 and 2017 were pre-approved by the audit committee.

OFF-BALANCE SHEET ARRANGEMENTS

Algonquin is not a party to any off-balance sheet arrangements that have, or are reasonably likely to have, a current or future material effect on its financial condition, results of operations or cash flows.

TABULAR DISCLOSURE OF CONTRACTUAL OBLIGATIONS

The information provided under the heading “Contractual Obligations” (page 41) in the Management’s Discussion and Analysis for the fiscal year ended December 31, 2017, filed as Exhibit 99.3 to this annual report on Form 40-F, is incorporated by reference herein.

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 annual report on Form 40-F, including the 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. generally accepting accounting principles. 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 the MD&A.

CAUTION CONCERNING FORWARD LOOKING STATEMENTS

This document may contain statements that constitute "forward-looking statements" or "forward-looking information" within the meaning of applicable securities legislation (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 are not limited to, statements relating to: expected future growth and results of operations; liquidity, capital resources and operational requirements; rate cases, 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; ongoing and planned acquisitions, projects and initiatives, including expectations regarding costs, financing, results and completion dates; 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 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; contractual obligations and other commercial commitments; environmental liabilities; dividends to shareholders; 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 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 disruptions or liability due to natural disasters 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; 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; loss of key customers; failure to realize the anticipated benefits of acquisitions; Atlantica or the Corporation's joint venture with Abengoa acting in a manner contrary to the Corporation's best interests; 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 "4. Enterprise Risk Factors" in our Annual Information Form for the fiscal year ended December 31, 2017, 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 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.

IDENTIFICATION OF THE AUDIT COMMITTEE

Algonquin 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" (page 61) identifying Algonquin's Audit Committee and confirming the independence of the Audit Committee in the Annual Information Form for the fiscal year ended December 31, 2017, 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, 2017 is filed as Exhibit 101 to this annual report on Form 40-F.

MINE SAFETY DISCLOSURE

Not applicable.

COMPARISON OF NYSE CORPORATE GOVERNANCE RULES

Algonquin is subject to corporate governance requirements prescribed under applicable Canadian corporate governance practices ("Canadian Rules"). Algonquin 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 Algonquin 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 Algonquin 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. Algonquin'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. Algonquin's Board of Directors also determines whether each member of its Audit Committee is independent pursuant to 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. Algonquin'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 the listed company be given the opportunity to vote on all equity-compensation plans and material revisions thereto. Canadian Rules generally require that shareholders approve all equity compensation plans, but the Canadian Rules are not identical to the NYSE Rules. Algonquin complies with Canadian Rules.

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. Algonquin has adopted its Board Mandate, which is the equivalent of corporate governance guidelines, in compliance with the Canadian Rules. Algonquin's corporate governance guidelines do not address director compensation, but Algonquin provides disclosure about the decision making process for non-employee director compensation in the annual management information circular and Algonquin 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. Algonquin's code of business conduct and ethics complies with Canadian Rules and does not include such a requirement.

UNDERTAKING

Algonquin 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

Algonquin 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 Algonquin shall be communicated promptly to the Commission by amendment to Form F-X referencing the file number of Algonquin.

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: March 7, 2018

By: /s/ David Bronicheski
Name: David Bronicheski
Title: Chief Financial Officer

EXHIBIT INDEX

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ALGONQUIN POWER & UTILITIES CORP.

ANNUAL INFORMATION FORM
For the year ended December 31, 2017

March 7, 2018

All information contained in this AIF is presented as at December 31, 2017*, unless otherwise specified. In this AIF, all dollar figures are in Canadian dollars, unless otherwise indicated.*

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Caution Concerning Forward-looking Statements and Forward-looking Information

This document may contain statements that constitute “forward-looking statements” or “forward-looking information” within the meaning of applicable securities legislation (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: 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; expectations with respect to the completion of the Atlantica transaction; the expected approval timing and purchase price of the Perris water distribution system transaction; the expected closing timing and amount of indebtedness to be assumed in relation to the St. Lawrence Gas Company, Inc. transaction; expectations and plans with respect to the Granite Bridge project; expectations with respect to revenues pursuant to energy production hedges; expected completion dates for projects under construction; expectations with respect to the Asbury Coal Power Plant; expected timing of post-closing adjustments related to the Long Sault Hydro Facility; 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; expected use of proceeds from the sale of common shares; business plans for APUC subsidiaries; and expected future base rates. 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 disruptions or liability due to natural disasters 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 appropriate 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; loss of key customers; failure to realize the anticipated benefits of acquisitions; Atlantica or the Corporation's anticipated joint venture with Abengoa acting in a manner contrary to the Corporation's best interests; 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 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 law. All forward-looking information contained herein is qualified by these cautionary statements.

Non-GAAP Financial Measures

The terms "Net Utility Sales", "Net Energy Sales" and "Adjusted EBITDA" are used throughout this AIF. These terms are not recognized measures under GAAP. There is no standardized measure of "Net Utility Sales", "Net Energy Sales" or "Adjusted EBITDA"; and 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", "Net Energy Sales" and "Adjusted EBITDA" can be found in APUC's MD&A for the year ended December 31, 2017 (which may be found on SEDAR at www.sedar.com and on EDGAR at www.sec.gov/edgar) under the headings "Liberty Power Group – 2017 Liberty Power Group Operating Results", "Liberty Utilities Group – 2017 Fourth Quarter Operating Results", "2017 Annual Operating Results", and "Non-GAAP Performance Measures – Reconciliation of Adjusted EBITDA to Net Earnings". Such calculations and analysis are incorporated by reference herein.

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 GAAP.

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 GAAP.

Adjusted EBITDA

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 and gain or loss on foreign exchange, earnings or loss from discontinued operations 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 Corporation. Where APUC manages the day to day operations of a facility and receives the majority of its economic benefits, the full operating profit of such facility is included in calculating the measure. 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 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 table on the following page excludes certain 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, 2017. 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.

The subsidiaries of APUC are grouped into two primary North American business units of the Corporation consisting of the Liberty Power Group and the Liberty Utilities Group. The following chart summarizes the major lines of business:

Liberty Power Group	Liberty Utilities Group
Hydro Electric Generation Solar Generation Thermal Co-Generation Wind Power Generation	Electric Utilities Natural Gas Utilities Water & Wastewater Utilities Natural Gas and Electric Transmission

Additional information on selected facilities owned by these business units is described in Schedules A, B, C, D, and E.

The following table outlines the Corporation's significant subsidiaries:

Significant Subsidiaries	Description	Jurisdiction	Ownership of Voting Securities
LIBERTY POWER GROUP			
Algonquin Power Co. (dba Liberty Power)		Ontario	100%
St. Leon Wind Energy LP ("**St. Leon LP**")	Owner of the St. Leon Wind Facility	Manitoba	100%
Algonquin Power Windsor Locks LLC	Owner of Windsor Locks Facility	Connecticut	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]
GSG6, 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]
LIBERTY UTILITIES GROUP			
Liberty Utilities (Canada) Corp. ("**LU Canada**")		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 natural gas distribution utility assets in Missouri, Iowa and Illinois	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%
Liberty Utilities (Park Water) Corp. ("**Liberty Park Water**")	Owner of the Liberty Park Water System in Downey, California	California	100%
Liberty Utilities (Apple Valley Ranchos Water) Corp. ("**Apple Valley**")	Owner of the Apple Valley Water System	California	100%
The Empire District Electric Company ("**Empire**")	Owner of (i) electric and water distribution utility assets serving locations in Missouri, Kansas, Oklahoma and Arkansas, (ii) 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 40% interest in the Stateline combined cycle gas facility in Missouri, and (iii) certain other generation facility and PPA interests.	Kansas	100%
The Empire District Gas Company	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%

[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. APUC also strives to achieve its results in the context of a moderate risk profile consistent with top-quartile North American power and utility operations.

The Corporation's operations are organized across two primary North American business units: the Liberty Power Group and the Liberty Utilities Group.

Liberty Power Group

The Liberty Power Group generates and sells electrical energy produced by its diverse portfolio of non-regulated renewable power generation and clean energy power generation facilities located across North America. The Liberty Power Group seeks to deliver continuing growth through development of new greenfield power generation projects and accretive acquisitions of additional electrical energy generation facilities and/or projects.

Liberty Utilities Group

The Liberty Utilities Group operates diversified regulated electricity, natural gas, water distribution and wastewater collection utility services. The Liberty Utilities Group provides safe, high quality, and reliable services to its customers through its nationwide portfolio of utility systems and delivers stable and predictable earnings to the Corporation. In addition to encouraging and supporting organic growth within its service territories, the Liberty Utilities Group delivers continued growth in earnings through accretive acquisition of additional utility systems.

2.1 Three Year History and Significant Acquisitions

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 2015

Corporate

(i) $150 Million Bought Deal Offering of Common Shares

On December 2, 2015, APUC issued, on a bought deal basis, 14,355,000 Common Shares at a price of $10.45 per share for gross proceeds of approximately $150 million. Net proceeds of the offering were used to partially fund APUC's capital growth program, to reduce short-term debt and for general corporate purposes.

Liberty Power Group

(i) Deerfield Wind Project Joint Venture

On October 19, 2015, the Liberty Power Group announced it had agreed to jointly develop the 150 MW Deerfield Wind Facility in Michigan with Renewable Energy Systems Americas Inc.

(ii) Great Bay Solar Project

On December 1, 2015, the Liberty Power Group announced the development of a new 75 MW contracted solar generation facility, located in Somerset County, Maryland. The facility is contracted under a 10 year PPA. The facility will also generate solar RECs which will be sold into the Maryland market. For more detail, see *"Description of the Business – Liberty Power Group – Description of Operations – Business Development"* below.

(iii) Completion of Bakersfield I Solar Project

On April 14, 2015, the Liberty Power Group achieved commercial operation of the 20 MW Bakersfield I Solar Facility located in Kern County, California. The electricity generated by the project is being sold under a 20 year PPA with a large investment grade electric utility. For more detail, see *"Description of the Business – Liberty Power Group – Description of Operations – Solar Power Generating Facilities"* below.

Liberty Utilities Group

(i) Successful Rate Case Outcomes

A core strategy of the Liberty Utilities Group is to ensure an appropriate return on the rate base at its various utility systems. During 2015, the Liberty Utilities Group successfully completed several rate cases representing a cumulative annual revenue increase of approximately U.S. $18.1 million.

(ii) U.S. Debt Private Placement

On April 30, 2015, the Liberty Utilities Group financing entity entered into a note purchase agreement for the issuance of U.S. $160 million of senior unsecured 30 year notes bearing a coupon of 4.13% via a private placement in the U.S. The proceeds of the financing were used to partially finance the acquisition of the Liberty Park Water System and for general corporate purposes. The notes were issued in two tranches: U.S. $90 million were issued immediately on closing and U.S. $70 million were issued on July 15, 2015. The notes were assigned a rating of BBB High by DBRS. The financing was the fourth series of notes issued pursuant to the Corporation's master indenture.

2.1.2 Fiscal 2016

Corporate

(i) Financing Related to the Empire Acquisition

In the first quarter of 2016, in connection with the acquisition of Empire (the " **Empire Acquisition**") discussed below, APUC and its direct wholly-owned subsidiary, LU Canada, entered into an agreement with a syndicate of underwriters under which the underwriters agreed to buy, on a bought deal basis, $1.15 billion aggregate principal amount of 5.00% convertible unsecured subordinated debentures ("**Debentures**") of APUC (the "**Debenture Offering**") and also obtained U.S. $1.6 billion in acquisition financing commitments from a syndicate of banks (the " **Empire Acquisition Facility**"). For more detail about the Empire business, see *"Description of the Business – Liberty Utilities Group – Description of Operations"* below.

(ii) Dual Listing of Algonquin Common Shares on the New York Stock Exchange

During the fourth quarter of 2016, APUC received approval to list the Common Shares for trading on the NYSE under the ticker symbol "AQN". The Corporation has been a U.S. Securities and Exchange Commission registrant since 2009 and operates primarily in the United States. APUC shares continue to be listed on the TSX also under the ticker symbol "AQN".

(iii) U.S. $235 Million Corporate Term Credit Facility

On January 4, 2016, the Corporation entered into a U.S. $235 million term credit facility with two U.S. banks. The proceeds of the term credit facility provided additional liquidity for general corporate purposes and acquisitions. The facility matures on July 5, 2018.

Liberty Power Group

(i) Acquisition of 75% interest in the Red Lily Energy Partnership

Effective April 12, 2016, the Liberty Power Group exercised its option to subscribe for a 75% equity interest in the Red Lily Wind Energy Partnership, a 26.4 MW wind energy facility (the "**Red Lily Wind Facility**") located in southeastern Saskatchewan for which the Liberty Power Group provides operation and supervision services.

(ii) Completion of the Odell Wind Facility

On July 29, 2016, the 200 MW Odell Wind Facility achieved commercial operation. On August 5, 2016, the tax equity financing of approximately U.S. $180 million was completed and on September 15, 2016 the Liberty Power Group acquired control of the project. The Odell Wind Facility has a 20 year PPA with a large investment grade utility. For more detail, see *"Description of the Business – Liberty Power Group – Description of Operations – Wind Power Generating Facilities"* below.

(iii) Purchase of Turbines to Safe Harbour Production Tax Credit Rate

At the end of 2016, the Liberty Power Group purchased approximately $75 million of turbine components that will qualify between 500 MW and 700 MW of new projects for 100% of the production tax credit ("**PTC**"). The full PTC is approximately U.S. $23 per MWh and subject to an annual adjustment for inflation. The PTC at the full rate is available to projects in the United States completed before the end of 2020 if they commenced construction prior to December 31, 2016 or have purchased components that qualify under the Internal Revenue Service safe harbor rules ("**Full PTC Projects**"). Projects other than Full PTC Projects will receive 80% of the applicable PTC rate if construction commences in 2017, 60% if construction commences in 2018, and 40% if construction commences in 2019. Securing access to the full PTC rate is an important competitive advantage in the U.S. market. The Liberty Power Group is currently evaluating projects to maximize the value of this equipment.

Liberty Utilities Group

(i) Acquisition of the Liberty Park Water System

On January 8, 2016, the Liberty Utilities Group closed a previously announced agreement to acquire a regulated water distribution utility holding company, Park Water Company, now known as Liberty Utilities (Park Water) Corp. (the "**Liberty Park Water System**"). The Liberty Park Water System owns and operates two regulated water utilities engaged in the production, treatment, storage, distribution, and sale of water in southern California and, at the time of closing, owned one regulated water utility in western Montana. Total consideration for the utility purchase was U.S. $341.3 million, which includes the assumption of approximately U.S. $91.8 million of existing debt.

The water utility located in western Montana was the subject of a condemnation lawsuit filed by the city of Missoula and has been the subject of certain related litigation and regulatory proceedings. Please see "*Legal Proceedings and Regulatory Actions - Regulatory Actions"* for a detailed description and discussion.

(ii) Successful Rate Case Outcomes

During 2016, the Liberty Utilities Group successfully completed several rate cases representing a cumulative annualized revenue increase of approximately U.S. $21.4 million.

2.1.3 Fiscal 2017

Corporate

(i) Completion of Financing Related to the Empire Acquisition

$1.15 Billion Bought Deal Offering of Convertible Unsecured Subordinated Debentures Represented by Instalment Receipts

Following the closing of the Empire Acquisition, the final instalment date was established as February 2, 2017 at which time APUC received the final instalment payment. To date, almost all of the Debentures had been converted into common shares of APUC, with APUC issuing approximately 108,384,716 common shares as a result of the conversion. The proceeds were used to repay a portion of APUC's bank facility drawn at closing of the Empire Acquisition Facility. For more detail about the Empire business, see *"Description of the Business – Liberty Utilities Group – Description of Operations"* below.

(ii) Extension of Dividend Reinvestment Plan

The Corporation announced on August 21, 2017 that eligible shareholders resident in the United States had then become able to enroll their Common Shares in the Corporation's shareholder dividend reinvestment plan (the "**Reinvestment Plan**"). Since its launch in 2011, the Reinvestment Plan was previously only available to residents of Canada.

(iii) Formation of Global Clean Energy and Water Infrastructure Joint Venture and Purchase of 25% Interest in Atlantica Yield plc

On November 1, 2017, APUC announced that it had entered into (a) a memorandum of understanding to create a joint venture (" **AAGES**") with Seville, Spain-based Abengoa S.A. ("**Abengoa**") 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 Yield

plc ("**Atlantica**") for a total purchase price of approximately U.S. $608 million, or U.S. $24.25 per ordinary share of Atlantica, plus a contingent payment of up to U.S. $0.60 per-share payable two years after closing, subject to certain conditions. The transaction is expected to close in the first quarter of 2018. Closing is subject to customary closing conditions.

(iv) Bought Deal 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 $13.25 per share for gross proceeds of approximately $576 million.

(v) Corporate Credit Facilities

During the third quarter of 2017, the Corporation's senior unsecured bilateral revolving facility was increased from $65 million to $165 million and the maturity was extended to November 19, 2018. During the fourth quarter of 2017, the Corporation entered into a term credit agreement in the amount of U.S. $600 million with a maturity of December 21, 2018 to support the closing of its transactions with Abengoa and Atlantica, as described above.

Liberty Power Group

(i) Issuance of $300 million Senior Unsecured Debentures

On January 17, 2017, the Liberty Power Group issued $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 $99.929 per $100.00 principal amount. Concurrent with the offering, the Liberty Power Group entered into a cross currency swap, coterminous with the debentures, to economically convert the Canadian dollar denominated offering into U.S. dollars. The net proceeds were used to partially finance the Odell Wind Facility, Deerfield Wind Facility and Bakersfield II Solar Facility.

(ii) Completion of Deerfield Wind Facility

On February 21, 2017, 150 MW Deerfield Wind Facility achieved commercial operation, on March 14, 2017, the Liberty Power Group acquired the remaining 50% interest in the project, and on May 10, 2017, tax equity financing of approximately U.S. $167 million was completed. The project has a 20 year PPA with a local electric distribution utility.

(iii) Great Bay Solar Project

On September 18, 2017, the Liberty Power Group entered into an equity capital contribution agreement with a third-party tax equity investor for a non-controlling interest in the Great Bay Solar Project. The tax equity investor will fund approximately U.S. $59 million.

(iv) Credit Facilities

On April 19, 2017, the Liberty Power Group entered into a $150 million senior unsecured bilateral revolving credit facility maturing on August 19, 2018. On October 6, 2017, the Liberty Power Group's syndicated revolving credit facility was increased from $350 million to U.S. $500 million and the maturity was extended to October 6, 2022.

Liberty Utilities Group

(i) Completion of the Empire District Electric Acquisition

On January 1, 2017, the Liberty Utilities Group successfully completed its acquisition of Empire for an aggregate purchase price of approximately U.S. $2.4 billion including the assumption of approximately U.S. $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 – Liberty Utilities Group – Description of Operations"* below. APUC has filed a business acquisition report dated March 10, 2017 in respect of the Empire Acquisition which may be found on SEDAR at www.sedar.com and on EDGAR at www.sec.gov/edgar.

(ii) Completion of Financing Related to the Empire Acquisition

On March 1, 2017, Liberty Utilities Group's financing entity entered into an agreement to issue U.S. $750 million of senior unsecured notes by way of private placement. The notes are of varying maturities ranging from 3 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 Empire Acquisition Facility and other existing indebtedness. For more detail about the Empire business, see *"Description of the Business – Liberty Utilities Group – Description of Operations"* below.

(iii) Completion of the Luning Solar Project

On February 15, 2017, the Liberty Utilities Group obtained control of a 50 MW solar generating facility located in Mineral County, Nevada (the "**Luning Facility**") for approximately U.S. $110.9 million. On February 17, 2017, the final tranche of the tax equity financing of approximately U.S. $39.0 million was completed. 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.

(iii) Approval to Acquire Perris Water Distribution System

On August 10, 2017, the Board approved the acquisition of two water distribution systems from the City of Perris, California for an anticipated purchase price of U.S. $11.5 million. The Perris City council approved the sale to the Liberty Utilities Group in July 2017 and the city's residents approved the sale on November 7, 2017. Approval of the acquisition by the CPUC is expected in 2018.

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

On August 31, 2017, the Liberty Utilities 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 proposed transaction is structured as a stock purchase in exchange for a cash purchase price of U.S. $70 million less the total amount of outstanding SLG indebtedness (which will be assumed by the Liberty Utilities Group at closing and is currently expected to be approximately U.S. $10 million), and is subject to customary working capital adjustments. Closing of the acquisition remains subject to regulatory approval and other customary closing conditions, and is expected to occur in 2018.

(v) Granite Bridge Project Announcement

On December 4, 2017, the Liberty Utilities Group announced plans for a new infrastructure project designed to bring additional natural gas supply to New Hampshire's residents and businesses. The project, called Granite Bridge, would bring natural gas from existing infrastructure located in New Hampshire's Seacoast region to the central part of the state through an underground pipeline. The proposed Granite Bridge project would connect the existing Portland Natural Gas Transmission System and Maritimes and Northeast Pipeline facilities in Stratham with the existing Tennessee Gas Pipeline facilities in Manchester. The Granite Bridge project also includes a proposed Liquefied Natural Gas storage facility capable of storing up to two billion cubic feet of natural gas. The final project will be subject to approval from regulatory authorities.

(vi) Successful Rate Case Outcomes

During 2017, the Liberty Utilities Group successfully completed several rate cases representing a cumulative annualized revenue increase of approximately U.S. $20.4 million.

2.1.4 Recent Developments - 2018

Corporate

(i) Change to U.S. Dollar Reporting

APUC has determined that, effective with the first quarter of 2018, APUC's interim and annual consolidated financial statements will be reported in U.S. dollars.

Liberty Power Group

(i) Increase to Letter of Credit Facility

On February 16, 2018, the Liberty Power Group increased availability under its revolving letter of credit facility to U.S. $200 million. The facility continues to be a one year extendible facility.

Liberty Utilities Group

(i) Liberty Utilities Credit Facilities

On February 23, 2018, the Liberty Utilities Group increased availability under its senior unsecured syndicated revolving credit facility from U.S. $200 million to U.S. $500 million and extended the maturity of such facility to 2023. The Liberty Utilities Group simultaneously canceled its U.S. $200 million revolving credit facility at Empire.

(ii) Pending Rate Case Filings

The Liberty Utilities Group has pending rate case filings in progress that represent an increase in rates in the amount of U.S. $44.4 million which are expected to be completed in 2018.

3. DESCRIPTION OF THE BUSINESS

3.1 Liberty Power Group

The Liberty Power Group generates and sells electrical energy produced by its diverse portfolio of non-regulated renewable power generation and clean power facilities located across North America. The Liberty Power Group owns or has interests in hydroelectric, wind, solar, and thermal facilities with a combined generating capacity of approximately 120 MW, 1,050 MW, 40 MW, and 335 MW, respectively. Approximately 87% of the electrical output from the hydroelectric, wind, and solar generating facilities is sold pursuant to long term contractual arrangements which as of December 31, 2017 had a production-weighted average remaining contract life of approximately 15 years. Details with respect to the Liberty Power Group's significant facilities and the term of material PPAs is set out in Schedules A and B.

3.1.1 Regulatory Regimes - Power Generation

(i) Canada

Much of the electricity supplied within the Canadian provinces is generated by government-owned corporations, such as OPG and Hydro-Québec. Independent power producers, such as the Corporation, provide additional capacity and supply to the grids. In Canada, the provinces have legislative authority over the generation, transmission and distribution of electricity. This in turn means that each province may have different requirements for the business to comply with in respect of the projects it owns in each province.

Generally speaking, each province in which the Corporation operates has various pieces of legislation in effect with which the business must comply. These relate to the generation, transmission and distribution of electricity in the province, the administration of the electric system, as well as the creation and authority of various governmental agencies who have oversight of an aspect of the industry, such as the ISO and the provincial energy board, utilities commission or other similar authority responsible for rate-making and regulatory oversight of the industry. In addition, some provinces require a generator of electricity to be licensed and registered with the appropriate governmental authority and the Corporation must comply with the conditions of license or registration accordingly. In addition to the legal requirements, the system operators have promulgated market rules to be complied with within their operating jurisdictions and any codes, rules and standards of the applicable energy board or utilities commission must be complied with.

(ii) United States

The power generation industry in the United States is regulated by the FERC under the U.S. Federal Power Act (" **FPA**"), the Energy Policy Act of 2005, the Public Utilities Regulatory Policies Act and the Public Utility Holding Company Act of 2005 ("**PUHCA**").

(1) Rate Regulation

All of the Liberty Power Group's operating U.S. power generation facilities are either: (1) exempt wholesale generators (" **EWGs**"); or (2) qualifying small power or cogeneration facilities ("**QFs**"). EWGs sell electricity exclusively in wholesale markets, while QFs with a power production capacity of 20 MW or less are exempt from most regulation under the FPA. There are two types

of QFs: (1) qualifying small power production facilities; and (2) qualifying cogeneration facilities. In order to be a qualifying small power production facility, which includes hydro, geothermal, solar and biomass, the facility must meet the maximum size and fuel use criteria specified in FERC's regulations. In order to be a qualifying cogeneration facility, the facility must meet the operating and efficiency criteria specified in FERC's regulations. All of the Liberty Power Group's operating U.S. power generation facilities that are EWGs possess FERC authorization to engage in sales for resale at market-based rates ("**MBR Authority**"). The QFs with a capacity greater than 20 MW also possesses MBR Authority. QFs with a capacity of 20 MW or less are not required to possess MBR Authority for their power sales, unless they are within a certain geographic proximity of one another. MBR Authority is available to EWGs and certain QFs and is obtained by showing that the generator and its affiliates do not possess vertical or horizontal market power in the relevant market. Once MBR Authority is obtained, the EWG or QF with a capacity greater than 20 MW, may sell its power into the relevant market at market-based rates. Each entity with MBR Authority must report its sales into the market by filing quarterly reports which details the relevant contracts used to sell power and the rates obtained for such power sales. QFs with a capacity of 20 MW or less are not required to file quarterly reports.

(2) NERC

The Energy Policy Act of 2005 expanded FERC's authority to impose mandatory reliability standards on the bulk electric system and to impose penalties on entities that manipulate the electric and natural gas markets. On June 20, 2006, NERC was certified by FERC as the Electric Reliability Organization for North America. NERC's mission is to ensure the reliability and security of the North American Bulk Electric System. NERC accomplishes its mission through enforcement of mandatory regulation of reliability operating standards. NERC also annually assesses seasonal and long-term reliability; monitors the bulk power system through system awareness; and educates, trains, and certifies industry personnel. NERC's area of responsibility spans the continental United States, Canada, and the northern portion of Baja California, Mexico. NERC is subject to oversight by FERC and governmental authorities in Canada. Some assets of the Liberty Power Group and the Liberty Utilities Group are subject to regulation by NERC.

(3) PUHCA

The Corporation is also subject to the PUHCA. PUHCA and FERC's implementing regulations impose certain books, records and accounting requirements on public utility holding companies. APUC is a public utility holding company and subject to such regulations. The Liberty Power Group's intermediate holding companies claims exemption from PUCHA under Title 18, Part 366.3 of the U.S. Code of Federal Regulations, which provides that a company that is a holding company solely by virtue of holding interests in QFs, EWGs and foreign utility companies is exempt from the books, records and accounting provisions of PUHCA and FERC's associated regulations. Should any of the EWGs or QFs cease qualifying for such status by no longer meeting the regulatory requirements for qualification, then the exemption would no longer apply. At that time, the books, records and accounting requirements would then apply.

3.1.2 Description of Operations

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.

(ii) Principal Markets and Distribution Methods

The principal markets in which the Liberty Power 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.

(1) Alberta

The electrical power industry in Alberta is regulated by the EUA. The AESO was established under the EUA to provide a competitive, real-time spot market for electric energy. The AESO is non-discriminatory and open to any generator, marketer, distributor, importer or exporter that satisfies the qualification requirements established under the EUA and the rules and codes of practice of the AESO.

(2) Ontario

The Ontario government develops the regulatory framework for wholesale and retail competition through the OEB. While transitional issues such as pricing and metering continue to be considered by the OEB, full competition in the wholesale and retail electricity market commenced on May 1, 2002.

The OEFC purchases the energy generated by the Ontario facilities and holds all rights, obligations and liabilities under the existing contracts. The Corporation's relevant subsidiary entities have also received a license to generate from the OEB as required by the *Ontario Energy Board Act, 1998* (Ontario).

(3) New Brunswick

Effective October 1, 2013, the New Brunswick government amended the provincial Electricity Act (New Brunswick), which resulted in the re-amalgamation of the NBSO with members of NB Power, a vertically-integrated group of companies, resulting in the transmission system operation functions of the NBSO being performed by NB Power's Transmission and System Operator division.

(4) Québec

Hydro-Québec is the primary electricity generator, transmitter, and distributor of electricity in the province of Québec; its sole shareholder is the Québec government. It uses mainly renewable generating options, in particular large hydro, and supports the development of other technologies, such as wind energy and biomass. It also sells power on wholesale markets in northeastern North America.

(iii) Material Facilities

(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 and Northern Maine, the Liberty Power Group 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.

(2) Dickson Dam Hydro Facility

The Dickson Dam Hydro Facility is located 20 km west of the Town of Innisfail, Alberta. The Dickson Dam Hydro Facility is a 15.0 MW hydroelectric generating facility utilizing the infrastructure located at the Dickson Dam and powered by the water flows of the Red Deer River. The Liberty Power Group sells all of the power generated at the Dickson Dam Hydro Facility in

the AESO at market rates. The Dickson Dam Hydro Facility is subject to a Use of Works Agreement with the Government of Alberta under which it has the right to utilize available water flows for generating power until March 31, 2030.

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.

(ii) Principal Markets and Distribution Methods

The principal markets for the Liberty Power Group's operational wind facilities in Canada are Manitoba for the St. Leon Wind Facilities, Saskatchewan for the Red Lily and Morse Wind Facilities, and Quebec for the Saint-Damase Wind Facility. The electricity generated by the wind turbines is transmitted to the transmission system of the purchaser, Manitoba Hydro in the case of the St. Leon Wind Facility and St. Leon II Wind Facility, SaskPower in the case of the Red Lily and Morse Wind Facility, and Hydro-Quebec in the case of the Saint-Damase Wind Facility. The principal markets for Liberty Power Group's wind facilities in the United States are the PJM, MISO and ERCOT regional markets.

(1) Manitoba

Historically, Manitoba Hydro had been exclusively responsible for the production of electricity in the province. Manitoba Hydro is a net exporter of electricity, mainly to Ontario and certain states of the United States. To date, the province has been able to utilize its large hydroelectric resources to satisfy internal and export requirements.

(2) Saskatchewan

Saskatchewan's electricity market remains under provincial government control and has not undergone any significant deregulation. SaskPower, the primary electricity utility in Saskatchewan, is wholly-owned by the province through the Crown Investments Corporation. SaskPower has set a target of 50% of generation capacity from renewables by 2030. As a result, SaskPower has a number of programs to encourage and solicit wind and other renewable power from independent producers.

(3) Québec

Hydro-Québec's hydroelectric portfolio accounts for 99% of its electricity mix and, as such, the utility has encouraged the development of wind projects in the province in recent years.

(4) Illinois and Pennsylvania

PJM is one of ten RTOs operating in North America. PJM, acting as a neutral, independent party, operates a competitive wholesale electricity market in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia.

(5) Michigan and Minnesota

MISO is an ISO, similar to an RTO, operating in fifteen U.S. states and the Canadian province of Manitoba. MISO assures consumers of unbiased regional grid management and open access to the transmission facilities through their functional supervision. MISO has interconnections with PJM, ERCOT, and other RTOs and ISOs. The fifteen states where MISO operates are: Arkansas, Illinois, Indiana, Iowa, Kentucky, Louisiana, Michigan, Minnesota, Mississippi, Missouri, Montana, South Dakota, North Dakota, Texas and Wisconsin.

(6) Texas

ERCOT, like PJM, is one of the ten RTOs operating in North America. ERCOT's region occupies the entire Texas interconnection which occupies nearly all of the state of Texas. Unlike the other major NERC interconnections, the high voltage transmission and energy market within the Texas interconnection is operated by ERCOT as essentially a single power system instead of as a network of cooperating utility companies. The portion of the electric grid in the State of Texas that is under the administration of ERCOT was – and remains – essentially unconnected to electrical grids in other states and, in the absence of "electricity in interstate commerce," does not fall under federal regulation.

(iii) Material Facilities

(1) St. Leon Wind Facility

The St. Leon Wind Facility is a 104 MW wind powered electrical generating facility located near St. Leon, Manitoba, 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, 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. The remaining generation and associated RECs are sold into the market.

(3) Sandy Ridge Wind Facility

The Sandy Ridge Wind Facility is a 50 MW wind powered electrical generating facility located near Tyrone, Pennsylvania, 180 km east of Pittsburgh. Sandy Ridge Wind, LLC is party to a long term energy production hedge (the "**Primary Energy Production Hedge**") with respect to the majority of production with J.P. Morgan Ventures Energy Corporation ("**JPMVEC**"), a wholly owned subsidiary of J.P. Morgan, having a term of 10 years beginning January 1, 2013 and is also party to an energy production hedge with another third party for production during 2023. 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, 200 km southwest of Chicago, IL. The Liberty Power Group first acquired an indirect interest in the Minonk Wind Facility on December 10, 2012. Minonk Wind, LLC is party to the Primary Energy Production Hedge with JPMVEC, having a term of 10 years beginning January 1, 2013 and is also party to an energy production hedge with another third party for production during 2023. Based on the JPMVEC contract quantity, approximately 73% of energy revenues are expected to be earned under the Primary Energy Production Hedge. Ancillary services, including capacity 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, 200 km west of Dallas, Texas. Senate Wind, LLC is party to the Primary Energy Production Hedge with JPMVEC, having a term of 15 years beginning January 1, 2013. Based on the JPMVEC contract quantity, approximately 64% of energy revenues are expected to be earned under the Primary Energy Production Hedge. 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, 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 150 MW wind powered electrical generating facility located in central Michigan, 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.

(iv) Renewable Energy Credits

RECs are tradeable commodities earned on the basis of 1 REC per MWh of electricity for wind generation facilities, and are used by utilities to satisfy compliance with RPS where necessary. These RPS mandates are set at a state level, and stipulate a certain amount of electricity to be generated from renewable sources by a specific year. Currently, the Minonk, Sandy Ridge, Senate, and Shady Oaks Wind Facilities each produce and sell RECs through bilateral contracts.

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, the Cornwall Solar Facility, Bakersfield I Solar Facility and the Bakersfield II Solar Facility, 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.

(ii) Principal Markets and Distribution Methods

The principal markets for the Liberty Power Group’s operational solar facilities are Ontario for the Cornwall Solar Facility and California for the Bakersfield I Solar Facility and the Bakersfield II Solar Facility. 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.

(1) Ontario

The IESO is an independent, non-profit corporation that is responsible for the real time operation, long term planning and procurement for Ontario’s electricity system. The IESO is licensed by the OEB and it reports to the Ontario legislature through Ontario's Ministry of Energy.

(2) California

The CAISO was formed in 1998 following a restructuring of the state electricity markets, and at the recommendation of the FERC. The CAISO operates as a non-profit public corporation responsible for operating the wholesale power system, maintaining the reliability of the grid, and planning for future demands. It is regulated by the FERC.

(iii) Material 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. The Bakersfield I Solar Facility achieved commercial operation in April 2015 and has a fixed rate PPA with an investment grade utility with a term of 20 years from commencement of commercial operation.

(iv) Renewable Energy Credits

RECs are tradeable commodities earned on the basis of 1 REC per MWh of electricity for solar generation facilities, and are used by utilities to satisfy compliance with RPS where necessary. These RSP mandates are set at a state level, and stipulate a certain amount of electricity to be generated from renewable sources by a specific year.

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.

(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.

(1) California

The electric transmission system and wholesale markets in California are primarily regulated by the CPUC and FERC. The CAISO administers the wholesale electricity marketplace for the region.

(2) Connecticut

The electricity markets and transmission systems in Connecticut are governed by the ISO-NE. The organization immediately assumed responsibility for managing the New England region's electric bulk power generation and transmission systems and administering the region's open access transmission tariff.

(iii) Material 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 and energy PPA with an investment grade utility expiring in 2021. The agreement calls for delivery of 38 MW of firm capacity.

(2) Windsor Locks Thermal Facility

The Windsor Locks thermal cogeneration facility (the "**Windsor Locks Facility**") is a 71 MW natural gas-fired generating facility located in Windsor Locks, Connecticut. The Windsor Locks 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.

(iv) Renewable Energy Credits

RECs are tradable commodities earned on the basis of 1 REC per 1.33 MWh of electricity for thermal generation facilities, and are used by utilities to satisfy compliance with RPS where necessary. Currently, the Windsor Locks Thermal Facility is qualified for Class III CT RECs for a portion of its production. The facility produces and sells RECs through bilateral contracts.

Business Development

(i) Strategy

The business development group works to identify, develop and construct new power generating facilities, as well as to identify and acquire operating projects that would be complementary and accretive to the Liberty Power Group's existing portfolio. The business development group is focused on projects within North America and is committed to working proactively with all stakeholders including local communities. The Liberty Power Group's approach to project development and acquisition is

to maximize the utilization of internal resources while minimizing external costs. This approach allows projects to mature to the point where most major elements and uncertainties are quantified and resolved prior to the commencement of project construction. Major elements and uncertainties of a project include the signing of a PPA, obtaining the required financing commitments to develop the project, completion of environmental and other required permitting, and fixing the cost of the major capital components of the project. It is not until all major aspects of a project are secured that the Liberty Power Group's business development group will begin construction or execute an acquisition agreement.

(ii) Principal Market Environment

The Liberty Power 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.

Within Canada, the market is driven largely by provincial regulations, of which Alberta and Saskatchewan are expected to present the most immediate opportunities for the Corporation. The AESO was commissioned by the Government of Alberta to develop recommendations for the procurement of renewable sources of power that will allow the Province to meet its objective to have 30% of electricity generation by 2030 come from renewable sources. One round of procurements was completed in 2017, with just under 600 MW of contracts awarded. Two additional upcoming rounds of procurements are expected in 2018 and 2019. Additional smaller procurement opportunities are being considered, including a solar procurement process with Alberta Infrastructure.

In Saskatchewan, the vertically-integrated utility SaskPower has set a target of 50% of generation capacity to come from renewables by 2030, which is expected to lead to the development of approximately 1,600 MW of new wind energy generation and 120 MW of utility-scale solar generation. The first competition commenced in 2017, with contracts expected to be awarded in the second quarter of 2018.

Within the United States, the most notable stimulus for the development of renewable power is the federal renewable electricity PTCs, a per-kilowatt-hour tax credit for electricity generated by qualified energy resources, and the federal investment tax credit, a tax credit for qualified renewable energy facilities based upon a percentage of eligible capital costs. On December 18, 2015, the United States Congress approved a five-year extension to the 30 percent federal investment tax credit for solar energy properties and U.S. 2.3 cents per kilowatt-hour PTC (subject to certain inflation adjustments) for wind facilities. The federal investment tax credit for solar energy will remain at 30 percent through 2019, before it phases down gradually to 10 percent in 2022. The PTC for wind energy was maintained at U.S. 2.3 cents per kilowatt-hour (subject to certain inflation adjustments) for projects on which construction was commenced prior to the end of 2016 before phasing down 20 percent per year and being eliminated at the end of 2019. Federal tax reform passed late in 2017 had no direct impact on these incentive programs. Additionally, other incentives continue to be offered independently for the development of renewable sources of power at the state and local levels. State policies continue to be driven by RPS, which vary between states. As of 2017, 29 states plus Washington D.C. and three territories have adopted binding RPS targets, and eight additional states have taken on voluntary renewable portfolio goals. These targets range between 8.5% and 50% of retail sales to specific entities, to be achieved between 2015 and 2040.

The Liberty Power Group will continue to pursue development projects which provide the opportunity to exhibit accretive growth within these markets.

(iii) Current Development or Construction Projects

The Liberty Power Group’s Development Division has successfully advanced a number of projects and has been awarded or acquired a number of PPAs. All of the projects contained in the table below meet the following criteria: a proven wind or solar resource, a signed PPA with a credit-worthy counterparty, and projected investment returns that meet or exceed APUC's investment return criteria.

Project Name	Location	Size (MW)	Commercial Operation	PPA Term (Years from COD)
Projects in Construction				
Amherst Island Wind Project	Ontario	75	2018	20
Great Bay Solar Project	Maryland	75	2018	10
Total Projects in Construction		**150**		
Projects in Development				
Blue Hill Wind Project	Saskatchewan	177	2019/20	25
Val-Éo Wind Project	Québec	24	2018	20
Total Projects in Development		**201**		
Total in Construction and Development		**351**		

(1) Amherst Island Wind Project

The Amherst Island wind project is a 75.0 MW wind powered electric generating development project located on Amherst Island near the village of Stella, approximately 15 km southwest of Kingston, Ontario (the "**Amherst Island Wind Project**"). The electricity to be generated by the project is being sold under a 20 year PPA awarded as part of the IESO FIT program. The project has a commercial operation date targeted for the second quarter of 2018.

(2) Great Bay Solar Project

The Great Bay Solar Project is a 75.0 MW solar powered electric generating development project located in Somerset County in southern Maryland. All energy from the project will be 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 will be retained by the project company and sold into the Maryland market. The project has a commercial operation date targeted for the first quarter of 2018.

(3) Blue Hill Wind Project

The Blue Hill wind project is a 177.0 MW wind powered electric generating development project located in Saskatchewan (the " **Blue Hill Wind Project**"). All of the energy from the project will be sold to SaskPower pursuant to a 25 year PPA awarded in 2016. The project is located in the rural municipality of Morse and Lawtonia, Saskatchewan.

The Blue Hill Wind Project will be developed as a single phase installation beginning in early 2019. The project requires final environmental approval and all other necessary permitting.

(4) Val-Éo Wind Project

The Val-Éo wind project is anticipated to be a 125 MW wind powered electric generating development project located in the local municipality of Saint-Gideon de Grandmont, which is within the regional municipality of Lac-Saint-Jean-Est, Quebec (the "**Val-Éo Wind Project**"). The project proponents include the Val-Éo Wind Cooperative which was formed by community based landowners and the Liberty Power Group.

The Liberty Power Group has a 50% equity interest in the project. It is believed that the first 24 MW phase of the Val-Éo Wind Project will qualify as Canadian Renewable Conservation Expense and, therefore, the project will be entitled to a refundable tax credit equal to approximately $16.0 million.

The project will be developed in two phases. Phase I of the project is expected to be completed in 2018 and is expected to have a total capacity of 24 MW, with all energy from Phase I of the project to be sold to Hydro-Quebec pursuant to a 20 year PPA. Phase II of the project would entail the development of an additional 101 MW and would be constructed following the successful evaluation of the wind resource at the site, completion of satisfactory permitting and entering into appropriate energy sales arrangements. All land agreements, construction permits, and authorizations have been obtained for Phase I.

The new schedule calls for Phase I construction to begin in the second quarter of 2018, with commissioning to occur in the fourth quarter of 2018.

(iv) Future Development Projects – Greenfield Projects

The Corporation continues to pursue new development opportunities in addition to building upon an existing portfolio of green-field sites. These projects represent a diversified range of opportunities within hydro, solar, wind and natural-gas modes of generation and are located throughout North America.

3.1.3 Specialized Skill and Knowledge

The Liberty Power Group's employees have extensive experience and contacts in the independent power industry in Canada and the United States. The energy from hydrology aspect of the business of the Liberty Power Group requires specialized knowledge of hydraulic turbines and their various components. This specialized knowledge is available to the Liberty Power Group in-house. The energy from wind aspect of the business of the Liberty Power Group requires specialized knowledge of wind turbines and their various components. This specialized knowledge is available to the Liberty Power Group in-house. On a more general level, the production of energy from all facilities requires specialized skill and knowledge, and the Liberty Power Group has employed various personnel who have such skill and knowledge.

3.1.4 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 should be an increase in the opportunity for the energy customer to choose the type of generation producing the electricity.

The U.S. Department of Energy has found that most utility customers want their utilities to pursue environmentally benign options for generating electricity and some customers are willing to pay extra to receive power generated by renewable resources. The Department of Energy believes that as deregulation and open competition evolve, the green power approach will help offset the relatively higher costs of renewable power compared to less costly gas-fired generation. Additionally, programs and policies are evolving at all government levels, allowing for the trading of greenhouse gas credits created by renewable energy projects to be seen as part of the eventual solution.

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 not subject to commodity fuel price volatility or risk. In addition, generation of the above forms of power generation 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 Liberty Power Group believes that future opportunities for power generation projects will continue to arise given that many jurisdictions, both in Canada and the United States, continue to increase targets for renewable and other clean power generation projects.
The Liberty Power Group is ideally positioned to take advantage of this demand for increased renewable energy, given that a significant portion of its assets are from renewable sources.

3.1.5 Cycles and Seasonality

(i) Hydroelectric Generating Facilities

The Liberty Power 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.

(ii) Wind Power Generating Facilities

The Liberty Power 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.

(iii) Solar Power Generating Facilities

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

3.2 Liberty Utilities Group

The Liberty Utilities Group operates a diversified portfolio of rate-regulated utilities throughout the United States that provide distribution services to approximately 762,000 connections in the natural gas, electric, water and wastewater sectors, with an approximate regional breakdown as follows:

	West	Central	East
Natural gas distribution	0	127,000	210,000
Electrical distribution	49,000	172,000	44,000
Water distribution	90,000	28,000	0
Wastewater collection	40,000	2,000	0
Total	179,000	329,000	254,000

The regulated electrical distribution utility systems and related generation assets are located in the states of Arkansas, California, Kansas, Missouri, New Hampshire, and Oklahoma. The regulated natural gas distribution utility systems are located in the states of Georgia, Illinois, Iowa, Massachusetts, New Hampshire and Missouri. The regulated water distribution and wastewater collection utility systems are located in the states of Arizona, Arkansas, California, Illinois, Missouri and Texas. The Liberty Utilities Group operates a fleet of regulated electric generation assets with a net capacity of 1,424 MW.

Details with respect to significant Liberty Utilities Group facilities and certain rate and tariff information is set out in Schedules C, D and E.

3.2.1 Regulatory Regimes - Utility Distribution Systems

Investor-owned utilities, whether water distribution and wastewater collection systems, electric distribution systems or gas distribution systems, are generally subject to economic regulation by the public utility commissions of the states in which they operate. The respective public utility commissions typically have jurisdiction over rates, service, accounting procedures, issuance of securities, acquisitions and other matters. The utilities generally operate under cost-of-service regulation as administered by these state authorities, using a 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 and deemed capital structure, together with all reasonable and prudent costs, establishes the revenue requirement upon which each utility's customer rates are determined. Rates

charged by these utilities are determined such that rates are set so as to provide the utilities with sufficient revenues to generate after-tax equity returns of approximately 8% to 12%. This oversight and other rules set by the state utility commissions are intended to ensure adequate supplies of water, electricity and natural gas together with financial security, transparency in the rate setting process and reasonable prices.

(i) Water Distribution and Wastewater Collection Systems

Generally, water and wastewater providers in the United States operate as geographic monopolies within the areas in which they serve. A water or wastewater company is typically provided a service territory defined by a CPCN which imposes an exclusive right and duty to serve in the service territory. A CPCN is typically granted by a State agency, which also serves as an economic and service quality regulator for these water or wastewater service providers. Such agencies are charged with ensuring that water and wastewater services are provided at reasonable rates and quality to the Corporation's customers. The agency must balance the interests of the utility customers as well as companies and their shareholders. Rates are approved by the agency to provide the water or wastewater company the opportunity, but not the guarantee, to earn a reasonable return on its investment after recovering its prudently incurred operating expenses.

(ii) Electric Distribution Systems

The electricity industry is highly regulated in the United States. The industry is regulated under strict standards at multiple levels - federal, state and sometimes local. Under the FPA, FERC regulates interstate transmission, wholesale sales of electricity, corporate acquisitions and dispositions, securities and debt issuances, debt acquisitions, and reliability. State utility commissions perform a similar role, regulating sales of electricity to end-use customers, as well as financial stability and reliability.

Generally, electricity distribution companies in the United States operate as geographic monopolies within the areas in which they serve. An electricity distribution company is typically provided a CPCN which imposes an exclusive right and duty to serve in the service territory. The approval to serve is typically granted by a State agency, which also serves as an economic and service quality regulator for these electric service providers. Such agencies are charged with ensuring that electric services are provided at reasonable rates and quality to customers. The agency must balance the interests of the utility customers as well as companies and their shareholders. Rates are approved by the agency to provide the electric service company the opportunity, but not the guarantee, to earn a reasonable return on its investment after recovering its prudently incurred operating expenses.

(iii) Natural Gas Distribution Systems

The natural gas industry is regulated at multiple levels - federal, state and sometimes local. Under the U.S. Natural Gas Act, FERC regulates interstate transmission and wholesale sales of gas. Interstate pipeline safety is regulated by the Department of Transportation. State utility commissions regulate retail distribution and sales of natural gas and intrastate pipelines. The federal pipeline safety requirements are often adopted by the state utility commissions and applied to intrastate pipelines and local distribution companies.

Generally, natural gas distribution companies in the United States operate as geographic monopolies within the areas in which they serve. A natural gas distribution company is provided a service territory which imposes an exclusive right and duty to serve in the service territory. The approval to serve is typically granted by a State agency, which also serves as an economic and service quality regulator for these natural gas service providers. Such agencies are charged with ensuring that natural gas services are provided at reasonable rates and quality to customers. The agency must balance the interests of the utility customers as well as companies and their shareholders. Rates are approved by the agency to provide the natural gas utility the opportunity, but not the guarantee, to earn a reasonable return on its investment after recovering its prudently incurred operating expenses.

3.2.2 Description of Operations

Water Distribution and Waste Water 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 waters 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 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 waters. 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 Liberty Utilities Group's water and wastewater facilities are located in the United States in the states of Arizona, Texas, Illinois, Missouri, Arkansas and California. 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.

(1) Arizona

The ACC is the primary regulatory agency with jurisdiction over water and wastewater treatment utilities in Arizona. The ADEQ and the Arizona Department of Water Resources in conjunction with various county agencies (county health units) have primary jurisdiction respecting environmental regulation, water regulation and compliance.

(2) Texas

The Public Utility Commission of Texas is the primary regulatory agency with jurisdiction over water and wastewater treatment utilities in Texas. This regulatory responsibility was transferred from the Texas Commission on Environmental Quality to the Public Utility Commission of Texas on September 1, 2014. The Texas Commission on Environmental Quality has regulatory jurisdiction respecting environmental compliance, including implementing and enforcing the standards mandated by the federal Clean Water Act and the Safe Drinking Water Act, for all water and wastewater treatment service providers, including those owned and operated by municipalities.

(3) Arkansas

The APSC is the primary regulatory agency with jurisdiction over the private and investor owned water utilities in Arkansas for rates and charges. The Arkansas Department of Health has regulatory jurisdiction respecting environmental compliance, including implementing and enforcing the standards mandated by the federal Clean Water Act and the Safe Drinking Water Act, for all water treatment service providers, including those owned and operated by municipalities. The Arkansas Department of Environmental Quality is the primary regulator for all discharge permits including wastewater treatment utilities in Arkansas.

(4) California

The CPUC is the primary regulatory agency with jurisdiction over the private and investor owned water utilities in California for rates and charges. The SWRCB has regulatory jurisdiction respecting environmental compliance, including implementing and enforcing the standards mandated by the California Safe Drinking Water Act and Title 17 and 22 of the California Code of Regulations (California has primacy) for all water service providers, including those owned and operated by municipalities. The jurisdiction respecting drinking water for CPUC-regulated water providers is shared between the CPUC and SWRCB pursuant to a Memorandum of Understanding. The SWRCB is the primary regulator for all discharge permits from drinking water systems in California.

(iii) Material Facilities

(1) Liberty Utilities (Litchfield Park Water & Sewer) Corp. Water & Wastewater Systems

The LPSCo System, located in and around the city of Goodyear 15 miles west of Phoenix, 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 5.8 million gallons per day.

(3) Liberty Park Water System

Liberty Park Water owns and operates three 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. Apple Valley (wholly-owned by Liberty Park Water) owns and operates the water system in Apple Valley, California.

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 California, New Hampshire, Missouri, Arkansas, Oklahoma and Kansas 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 Liberty Utilities 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, which is the methodology utilized in California. 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.

(1) California

The CPUC regulates investor owned utilities in California and approves the rate of return and the rate base which affects the profitability of the utility.

The ECAC is an annual filing that sets rates to recover the next year's fuel and purchased power costs in addition to setting rates to recover or refund any under/over recovery of previous year's fuel and purchased power costs.

Post Test Year Adjustment Mechanism allows the CalPeco Electric System to update its rates annually by a cost inflation index. In addition, rates are updated to recover the return on investment and associated depreciation of major capital projects that are placed in service and meet a certain cost threshold.

The BRRBA removes the seasonal variations of the revenues and flattens the net revenue (minus fuel, purchased power, and ECAC) to a fixed monthly rate. This eliminates the risk of revenue variations associated with seasonal weather changes.

(2) New Hampshire

The NHPUC is vested with general jurisdiction over electric, telecommunications, natural gas, steam, water and sewer utilities as defined in applicable legislation for issues such as rates, quality of service, finance, accounting, and safety. Utility companies are allowed to file distribution rate cases from time to time as the companies determine a need to request adjustments to base rates. There are a number of adjustment factors also in rates, for reliability enhancement programs, vegetation management, energy efficiency and low income programs, all of which are reconciled on an annual basis. Electricity distribution companies are also required to provide electricity commodity service for its customers who do not elect to take service from a competitive supplier. Costs for commodity service are recovered on a direct pass through basis.

(3) Missouri

The Corporation's Missouri operations are regulated by the MPSC. The rates and fees for providing electric service to end users and recovering the authorized rate of return are in the form of a fixed monthly charge and a volumetric distribution charge. The rates billed to recover fuel costs are charged through the Fuel Adjustment Clause.

(4) Arkansas

The APSC is the primary regulatory agency with jurisdiction over the investor owned electric utilities in Arkansas for rates and charges.

(5) Oklahoma

The OCC is the primary regulatory agency with jurisdiction over rates and charges of investor owned utilities in Oklahoma.

(6) Kansas

The KCC is the primary regulatory agency with jurisdiction over rates and charges of investor owned utilities in Kansas.

(iii) Material 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 commencing January 2016. The PPA obligates NV Energy to use commercially reasonable efforts to supply the CalPeco Electric System with sufficient renewable power to, combined with the Luning Facility, satisfy the current California Renewables Portfolio Standard requirement for the five year term of the PPA. The CalPeco Electric System has received approval from CPUC to recover the costs it will incur under 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 Facility. On January 31, 2017, the Federal Energy Regulatory Commission authorized transactions between the Luning Facility and the CalPeco Electric System pursuant to the PPA with NV Energy. The system is also subject to FERC regulation.

(2) Granite State Electric System

The Granite State Electric System provides distribution service in southern and northwestern New Hampshire, centered around operating centers 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.

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 ("**Default Service**") in the New England power market, and is allowed to fully recover its costs for the provision and administration of Default Service under the Default Service Adjustment Provision, 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. The Empire District Gas Company is a wholly owned subsidiary engaged in the distribution of natural gas in Missouri. The largest urban area served by Empire's gas operations is the city of Sedalia. Empire also operates a fiber optics business. The utility portions of the business are subject to regulation by the MPSC, the KCC, the OCC, the APSC and the 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 Liberty Utilities 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 & Regulatory Environments

The Liberty Utilities Group owns and operates natural gas distribution systems, under cost-of-service regulation in the states of Illinois, Iowa, Missouri, Georgia, Massachusetts and New Hampshire. The natural gas utilities use a test year to determine distribution rates for the utility. Pursuant to this 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 in order to ensure it earns a reasonable rate of return on its investments.

(1) New Hampshire

In New Hampshire, gas utilities are regulated by the NHPUC. The NHPUC is vested with general jurisdiction over electric, telecommunications, natural gas, steam, water and sewer utilities as defined in applicable legislation for issues such as rates, quality of service, finance, accounting, and safety. The rates and fees for providing gas service to end users and recovering the authorized rate of return are in the form of a fixed monthly charge and a volumetric distribution charge. The rates billed to recover gas costs are in the form of the tariffed PGA.

(2) Illinois

The Liberty Utilities Group's Illinois operations are regulated by the Illinois Commerce Commission. The rates and fees for providing gas service to end users and recovering the authorized rate of return are in the form of a fixed monthly charge and a volumetric distribution charge. The rates billed to recover gas costs are in the form of the tariffed PGA.

(3) Iowa

The Liberty Utilities Group's Iowa operations are regulated by the Iowa Utilities Board. The rates and fees for providing gas service to end users and recovering the authorized rate of return are in the form of a fixed monthly charge and a volumetric distribution charge. The rates billed to recover gas costs are in the form of the tariffed PGA.

(4) Missouri

The Liberty Utilities Group's Missouri utility operations are regulated by the MPSC. The rates and fees for providing gas service to end users and recovering the authorized rate of return are in the form of a fixed monthly charge and a volumetric distribution charge. The rates billed to recover gas costs are in the form of the tariffed PGA.

(5) Georgia

The Liberty Utilities Group's Georgia operations are regulated by the Georgia Public Service Commission. The rates and fees for providing gas service to end users and recovering the authorized rate of return are in the form of a fixed monthly charge and a volumetric distribution charge. The rates billed to recover gas costs are in the form of the tariffed PGA.

(6) Massachusetts

The Liberty Utilities Group's Massachusetts operations are regulated by the Commonwealth of Massachusetts. The MDPU has regulatory jurisdiction over all public utilities and common carriers operating in the Commonwealth, which jurisdiction includes the establishment of approved tariffed rates for the purpose of billing customers. The rates and fees for providing

gas service to end users and recovering the authorized rate of return are in the form of a fixed monthly charge and a volumetric distribution charge. The rates billed to recover gas costs are in the form of the tariffed PGA.

(iii) Material 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, New Hampshire. The EnergyNorth Gas System's customer base consists of a mixture of residential, commercial, industrial and transportation customers.

The EnergyNorth System in New Hampshire recently filed two applications with the New Hampshire Public Utilities Commission to obtain the franchise rights to provide gas to new territories. One was filed in November 2016 seeking approval to obtain the franchise rights to the Town of Hanover and City of Lebanon. A settlement has been reached in this docket and the Corporation is currently awaiting a final decision order. Another application was filed in August 2015 seeking the franchise rights to the towns of Pelham and Windham, which has been approved by the NHPUC.

(2) Empire District Gas System

EDG is engaged in the distribution of natural gas in Missouri and serves approximately 43,000 customers. 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, and Hamilton, GA. 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 are reviewed and updated annually through a tariff provision called the GRAM. This mechanism allows 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%. The Peach State Gas System also files an annual Pipe Replacement Program revision to adjust the rates collected for capital costs incurred to replace cast iron and bare steel pipe in its system.

Georgia allows full recovery of all gas costs (including commodity price, transportation, reservation and demand costs, hedging costs, storage costs). The PGA requires a change in rates at least every three months.

(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 System

The Midstates Gas System owns regulated natural gas utilities providing natural gas distribution services to approximately 190 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 allows full recovery of all gas costs (including commodity price, transportation, reservation and demand costs, hedging costs, and storage costs). The rate is adjusted monthly with an annual reconciliation based on the calendar year. Iowa allows full recovery of all gas costs (including commodity price, transportation, reservation and demand costs, hedging costs, and storage costs). The rate is adjusted monthly with an annual reconciliation based on the twelve months ended August of each year. Missouri allows full recovery of all gas costs (including commodity price, transportation, reservation and demand costs, hedging costs, and storage costs). The rate is adjusted annually (in fourth quarter) with allowance to file quarterly.

Natural Gas and Electric Transmission

(i) Method of Providing Services and Distribution 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.

(ii) Principal Markets & 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.

The Empire transmission facilities are located within a four state area of Missouri, Kansas, Oklahoma, and Arkansas and 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 SPP regional entity for NERC compliance, SPP Market Rules, and the FERC.

Business Development

The Liberty Utilities Group's strategy is to grow its business organically and through business development activities while using prudent acquisition criteria.

Granite Bridge

On December 4, 2017, the Liberty Utilities Group announced plans for a new infrastructure project designed to bring additional natural gas supply to New Hampshire’s residents and businesses. The project, called Granite Bridge, would bring natural gas from existing infrastructure located in New Hampshire’s Seacoast region to the central part of the State through an underground pipeline. The proposed Granite Bridge project would connect the existing Portland Natural Gas Transmission System and Maritimes and Northeast Pipeline facilities in Stratham with the existing Tennessee Gas Pipeline facilities in Manchester. The Granite Bridge project also includes a proposed Liquefied Natural Gas storage facility capable of storing up to two billion cubic feet of natural gas. The final project will be subject to approval from regulatory authorities.

Empire District Electric Wind Projects

On October 31, 2017, the Liberty Utilities Group filed a plan with regulators to expand its wind energy resource. The plan calls for the development of up to 800 MW of new wind generation strategically located in or near its service territory by the

end of 2020. As part of this proposed plan, the energy generated by the wind farm is expected to replace the energy currently generated by the Asbury Coal Power Plant. This plan is subject to regulatory approval, which is currently expected to be received by the summer of 2018.

3.2.3 Specialized Skill and Knowledge

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

3.2.4 Competitive Conditions

The Liberty Utilities Group's businesses have geographic monopolies in their service territories. The Liberty Utilities Group has developed significant in-house regulatory expertise in order to effectively interact with the state regulators in the various jurisdictions in which it operates. The Liberty Utilities 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.

3.2.5 Cycles and Seasonality

(i) Water and Wastewater Systems

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 Corporation attempts to mitigate the above noted risks by seeking regulatory mechanisms during rate case proceedings. Certain jurisdictions have approved constructs to mitigate demand fluctuations. For example, the Central Basin and Apple Valley facilities in California, 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. Not all regulatory jurisdictions in which the Liberty Utilities Group operates have approved mechanisms to mitigate demand fluctuations.

Water distribution facilities 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 the utilities. Government restrictions on water usage during drought conditions could also result in decreased demand for water, even if supplies are adequate, which could adversely affect revenues and earnings.

(ii) Electricity Systems

The CalPeco Electric System's demand for energy sales are primarily affected by weather conditions. Above normal snowfall in the Lake Tahoe area brings more tourists with an increased demand for electricity by small commercial customers. The CalPeco Electric System has implemented a BRRBA rate mechanism that removes the seasonal variations of revenues and flattens the net revenue (gross revenues less fuel, purchased power, and the ECAC deferral) to a fixed monthly amount. This mechanism eliminates the risk of revenue variations associated with seasonal weather changes.

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 Default Service price for power may fluctuate as a result of the weather, but those costs are passed through directly to customers.

The Granite State Electric System offers a comprehensive menu of energy efficiency programs in New Hampshire that, in turn, may reduce the demand for energy. These programs are funded via a charge in distribution rates known as the systems benefit charge, which applies to all utilities. This mechanism provides for an annual reconciliation of costs. The company has an opportunity to earn a performance incentive if it is successful in achieving its annual energy efficiency targets.

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 Default 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 Liberty Utilities 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 Liberty Utilities Group attempts to mitigate the above noted risks 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 in Georgia, 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. Not all regulatory jurisdictions in which the Liberty Utilities Group operates have approved mechanisms to mitigate demand fluctuations.

3.3 Related Party Transactions

(i) Equity-method investments

The Corporation provides administrative services to its equity-method investees and is reimbursed for incurred costs. To that effect, the Corporation charged its equity-method investees $6.0 million in 2017 as compared to $3.3 million during the same period in 2016.

(ii) Long Sault Hydro Facility

Effective December 31, 2013, APUC acquired the shares of APCI 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 is expected to be settled in 2018.

3.4 Principal Revenue Sources

APUC owns, directly or indirectly, interests in renewable generation facilities, thermal generation facilities, electrical 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, 2016 and December 31, 2017:

	% Total Revenue	
	December 31, 2017	**December 31, 2016**
Non-regulated energy sales	14.3%	22.2%
Utility electricity sales & distribution	50.0%	20.8%
Utility natural gas sales & distribution	24.8%	37.0%
Utility water distribution and wastewater treatment sales & distribution	9.2%	16.6%
Other revenue[1]	1.7%	3.4%

[1] Other revenue includes gas transportation and RECs.

The purchase of electricity and natural gas by the Corporation's electric distribution and natural gas distribution system 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 Liberty Power Group (see *Non-GAAP Financial Measures*) and Net

Utility Sales at the Liberty Utilities 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, 2016 and December 31, 2017:

	% Net Energy Sales/Net Utility Sales	
	December 31, 2017	**December 31, 2016**
Non-regulated energy sales	17.5%	27.6%
Utility electricity sales & distribution	47.8%	13.5%
Utility natural gas sales & distribution	20.9%	33.0%
Utility water distribution and wastewater treatment sales & distribution	11.6%	21.2%
Other revenue[1]	2.2%	4.7%

[1] Other revenue includes gas transportation and RECs.

For the Liberty Power Group, the following provides a breakdown of revenue by percentage for the years ended December 31, 2016 and December 31, 2017:

	% Revenue	
	December 31, 2017	**December 31, 2016**
Hydroelectric generation	19.4%	25.0%
Wind generation	57.2%	48.2%
Solar generation	4.7%	4.9%
Thermal generation	12.9%	13.4%
Other revenue[1]	5.8%	8.5%

[1] Other revenue includes RECs.

For the Liberty Utilities Group, the following provides a breakdown of revenue by percentage for the years ended December 31, 2016 and December 31, 2017:

	% Revenue	
	December 31, 2017	**December 31, 2016**
Utility electricity sales & distribution	59.0%	27.5%
Utility natural gas sales & distribution	29.3%	48.9%
Utility water distribution and wastewater treatment sales & distribution	10.8%	21.9%
Other revenue[1]	0.9%	1.8%

[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, 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, 2017. 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*"). Many of these risks are mitigated through the maintenance of adequate insurance which include property, boiler and machinery, environmental and excess liability policies.

3.6 Employees

The Corporation's Executive Management Group consists of eight individuals including the Chief Operating Officers of the Liberty Power Group and the Liberty Utilities Group. As at December 31, 2017, the Corporation employed a total of 2,241 people.

The Liberty Power Group employed a total of 109 employees as at December 31, 2017. All of the employees of the Liberty Power Group are non-unionized.

The Liberty Utilities Group employed a total of 1,854 employees as at December 31, 2017. The Liberty Utilities Group employees are non-unionized with the exception of: 66 employees at the CalPeco Electric System, 41 employees at the Midstates Gas System, 346 employees at The Empire District Electric Company, 183 employees at the EnergyNorth Gas System and Granite State Electric System, and 82 employees at the New England Gas System.

The corporate and shared services groups consisted, as at December 31, 2017, of an additional 194 employees located at the corporate offices in Oakville, Ontario and an additional 76 shared services employees located throughout the United States.

3.7 Foreign Operations

For the twelve months ended December 31, 2017, approximately 100% of the revenue of the Liberty Utilities Group and 70% of the revenue of the Liberty Power 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 either for the sale of a major part of its products and services or for the purchase of a major part of its requirements for goods, services or raw materials or any franchise or license or other agreement to use a patent formula, trade secret, process or trade-name upon which its business depends.

3.9 Social or Environmental Policies

The Corporation has formal policies and procedures that support its commitment to corporate responsibility. The Corporation's Code of Business Conduct and Ethics is the foundation of the Corporation's corporate responsibility framework. As a condition of employment, all employees 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. During the course of business, any compliance exceptions are reviewed and managed promptly.

The Corporation's businesses have safety and environmental compliance policies in place. These policies have been communicated with staff, and have been incorporated into their respective Safety Mission Statements and Employee manuals.

The Corporation has an Environmental, Health and Safety Group that reports independently to the Corporation's Vice President, People and Culture. This group is responsible for developing environmental and safety policies, developing and delivering

environmental and safety training, conducting internal audits of environmental and safety performance, and arranging for third party environmental and safety audits.

The Corporation is actively involved in corporate responsibility. Using the Global Reporting Initiative, an international independent standards organization that helps businesses, governments and other organizations understand and communicate their impacts on issues such as climate change, human rights and corruption, the Corporation formally tracks several Global Reporting Initiative indicators. With corporate responsibility as an element of the Corporation's decision making, the Corporation reduces liability for investors, increases morale and engagement of employees, creates an environmentally cleaner community, and enhances the partnership with all of its stakeholders.

Corporate responsibility 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 has environmentally supportive 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. The economic branch of the Corporation's corporate responsibility efforts incorporates 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, health and safety policies, diversity in the workplace, and community involvement. The Corporation believes this philosophy will contribute to a sustainable future for its investors, communities, environment, customers, employees, governments, and business partners.

3.10 Credit Ratings

The Corporation maintains the following credit ratings by the rating agencies [1]:

	S&P		DBRS		Moody's	
	2017	2016	2017	2016	2017	2016
APUC - Issuer rating	BBB	BBB	BBB (low)	BBB(low)	-	-
APUC - Preferred Shares	P-3 [3]	P-3 [3]	Pfd-3 (low)	Pfd-3 (low)	-	-
APCo - Issuer rating	BBB	BBB	BBB (low)	BBB (low)	-	-
APCo - Senior unsecured debt	BBB	BBB	BBB (low)	BBB (low)	-	-
Liberty Utilities Co.	BBB	BBB	-	-	-	-
Liberty Utilities Finance GP1 - Issuer rating [2]	-	-	BBB (high)	BBB (high)	-	-
Liberty Utilities Finance GP1 - Senior unsecured notes	-	-	BBB (high)	BBB (high)	-	-
Empire - Issuer rating	BBB	BBB	-	-	Baa1	Baa1
Empire - First mortgage bonds			-	-	A2	A2
Empire - Senior unsecured debt			-	-	Baa1	Baa1
Empire - Commercial paper			-	-	P-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 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.

[3] P-3 rating is equivalent to a BB rating on S&P's global preferred share rating scale

S&P

S&P rates debt instruments and issuers with ratings ranging from “AAA”, which represent the greatest ability of an obligor to meet its financial commitment, to “D”, which represents an obligor in payment default. A rating of “BBB” by S&P denotes an obligor having adequate capacity to meet its financial commitments. Adverse economic conditions or changing circumstances are more likely to lead to a weakened capacity of the obligor to meet its financial commitments. An S&P rating 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.

According to the S&P rating system, preferred shares rated P-3 are regarded as having significant speculative characteristics. While such securities will likely have some quality and protective characteristics, these may be outweighed by large uncertainties or major exposures to adverse conditions. The ratings from P-1 to P-5 may be modified by “high” and “low” grades which indicate relative standing within the major rating categories.

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 represent debt instruments for which a company has not made a scheduled payment of interest or principal or has made it clear it will miss such a payment in the near future. A rating of “BBB” by DBRS denotes an obligor having adequate credit quality. Protection of interest and principal is considered acceptable, but the entity is fairly susceptible to adverse changes in financial and economic conditions, or there may be other adverse conditions present which reduce the strength of the entity and its rated securities. A DBRS rating may be modified by the addition of a “(high)” or “(low)” to indicate the relative standing within a particular rating category. The absence of either a “(high)” or “(low)” designation indicates that the rating is in the middle of the category.

According to the DBRS rating system, preferred shares rated Pfd-3 are of adequate credit quality. While protection of dividends and principal is still considered acceptable, the issuing entity is more susceptible to adverse changes in financial and economic conditions, and there may be other 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.

Moody's

Moody's rates debt instruments and issuers with ratings ranging from “Aaa”, which represent the greatest ability of an obligor to meet its financial commitment, to “C”, which represents an obligor in payment default. A rating of “A” by Moody's denotes obligations judged to be upper-medium grade and are subject to low credit risk, while a rating of “Baa” by Moody's denotes an obligations judged to be medium-grade and subject to moderate credit risk and as such may possess certain speculative characteristics. A Moody's rating may be modified by the addition of a numerical modifiers 1, 2, and 3 to show relative standing within the major rating categories.

Short-term obligations of an issuer 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 “P-3”, which represent an issuer's acceptable ability to repay short-term obligations.

4. ENTERPRISE RISK FACTORS

The Corporation is subject to a number of risks and uncertainties. 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. The description of risks below does not include all possible risks.

An enterprise risk management, or ERM, framework is embedded across the organization that systematically and broadly identifies, assesses, and mitigates 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 ERM policy details the risk management processes, risk appetite, and risk governance structure which clearly establishes accountabilities for managing risk across the organization.

As part of the risk management processes, risk registers have been developed across the organization through ongoing risk identification and risk assessment exercises facilitated by the Corporation's internal ERM team. Risk information is sourced throughout the organization using a variety of methods including risk identification interviews and workshops, as well as the Corporation's "Risk Insights" program, which provides all employees with a mechanism to communicate risks and opportunities at any time. 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 on a quarterly basis.

Risks are evaluated consistently across the organization using a common 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 development and execution of risk treatment plans for the organization's top risks are actively monitored by the Executive team. The Corporation's internal audit team is responsible for conducting audits to validate and test the effectiveness of controls for key risks. Audit findings are discussed with business owners and reported to the Audit Committee on a quarterly basis. All material changes to exposures, controls or treatment plans of key risks are reported to the ERM team, Enterprise Risk Management Council, the Corporate Governance and Risk Committees, and the Board for consideration.

The Corporation's ERM framework follows the guidance of ISO 31000:2009. The Board oversees management to ensure the risk governance structure and risk management processes are robust, and that the Corporation's risk appetite is thoroughly considered in decision-making across the organization.

4.1 Risk Factors Relating to Operations

The Corporation's operations involve numerous risks that could disrupt or adversely affect its business, results of operations, financial position and cash flows.

The operation of the Corporation's power generation facilities, utility systems and other assets involve a variety of risks customary to the power and utilities sector, including:

- severe weather conditions and natural disasters;
- global climate change;
- environmental contamination/wildlife impacts;
- casualty events such as fires, explosions, security breaches or other occurrences;
- commodity supply and transmission constraints or interruptions;
- workplace and public safety events;
- loss of key personnel;
- labour disputes;
- poor employee performance/workforce effectiveness;
- 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;
- lower-than-expected levels of efficiency or operational performance;
- wars and terrorist acts;
- commodity price;
- obligations to serve; and
- the Corporation's reliance on subsidiaries.

These and other operating events and conditions could result in service 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 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 would, 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 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 global warming and overall 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 cells. 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 Liberty Power 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 Liberty Utilities 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 is subject to physical and financial risks associated with global climate change.

Global climate change creates physical and financial risk. Physical risks from climate change may include an increase in sea level and changes in weather conditions, such as changes in precipitation and extreme weather events. Customers' energy needs vary with 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 could 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), operations adjustments or liability, and related financial impacts, resulting from wildlife mortality monitoring, emissions including noise and dam safety.

In addition, like other industrial companies, 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.

The Corporation's facilities and operations are exposed to effects of natural disasters and other catastrophic events beyond the Corporation's control and such events could result in a material adverse effect.

The Corporation's facilities and operations are exposed to potential interruption and damage, and partial or full loss, resulting from environmental disasters (e.g. floods, high winds, fires, ice storms, and earthquakes), other seismic activity, equipment failures and the like. There can be no assurance that in the event of an earthquake, hurricane, tornado, tsunami, typhoon, terrorist 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 power purchase agreements from purchasing electricity, could have a material negative impact on the Corporation's business. The Corporation's infrastructure 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 power purchase agreements or other agreements with third parties.

Certain of the Corporation's utilities operate in remote and mountainous terrain with a risk of loss or damage from forest fires, floods, washouts, landslides, earthquakes, avalanches and other acts of nature.

Security breaches, criminal activity, terrorist attacks and other disruptions to the Corporation's information technology infrastructure 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 and systems 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 and systems 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 information technology networks 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, natural disasters or other catastrophic events. 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 identify and remedy all 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. 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.

Certain events or conditions, such as an aging workforce, epidemic or pandemic, mismatch of skill set or complement to future needs, or unavailability of contract resources may lead to operating challenges 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 Liberty Power Group, the availability of water to be distributed by the Liberty Utilities Group and the demand for the utility services of the Liberty Utilities Group.

Demand for energy sold to retail customers in the maritime region is primarily affected by temperature. Demand for energy during colder months is generally greater than warmer months as the load served is located in a "winter peaking" region.

The Liberty Utilities 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 Liberty Utilities 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 – Liberty Power Group – Cycles and Seasonality* " and "*Description of the Business – Liberty Utilities Group – Cycles and Seasonality*" for a detailed description and discussion of this risk.

The Corporation historically has, and may in the future, enter into long-term power purchase contracts 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 Liberty Power Group sells a significant portion of the energy (and renewable energy credits) it generates under long-term power purchase agreements. To the extent a generating asset is not fully covered by a power purchase contract, the Liberty Power Group may enter into financial or physical power hedges to reduce the risk from fluctuations in market price. For instance, several of the Liberty Power Group's wind energy production facilities are subject to long-term 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 favorable 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 force the Liberty Power 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.

Liberty Power 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 Liberty Power Group's power generation facilities depend on electric transmission systems and related facilities owned and operated by third parties to deliver the electricity the Liberty Power 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 Liberty Power 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 Liberty Power 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 power purchase agreements or to construct new projects. Any such increased costs and delays could delay the commercial operation dates of Liberty Power Group's new projects and negatively impact the Corporation's revenues and financial condition.

The Corporation's subsidiaries do not own all of the land on which their projects are located and their use and enjoyment of real property rights for their 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 their business, results of operations, financial condition and cash flows.

The Corporation's subsidiaries do not own all of the land on which their 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's operating subsidiaries may be subject to the rights of these third parties, and the rights of the Corporation's operating subsidiaries to use the land on which their projects are or will be located and their projects' 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's operating subsidiaries to use the land on which their projects are or will be located could have a material adverse effect on their 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.

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

The long-term impact of terrorist attacks and the magnitude of the threat of future terrorist 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 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 our 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 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 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 Liberty Utilities Group, commodity price exposure is primarily limited to the cost of electricity and natural gas. Although the Liberty Utilities 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.

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 energy service 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 Liberty Utilities 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 Liberty Utilities Group may have facilities located within areas of the United States experiencing growth. These utilities may have an obligation to service new residential, commercial and industrial customers. While expansion to serve new customers will likely result in increased future cash flows, it may require significant capital commitments in the immediate term. Accordingly, the Liberty Utilities 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 us.

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 their 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 Liberty Utilities 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 Liberty Power Group.

4.2 Risk Factors Relating to Financing and Financial Reporting

A downgrade in the Corporation's credit rating 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.

The Corporation has a long term consolidated corporate credit rating of BBB (flat) from S&P and a BBB (low) rating from DBRS. Liberty Utilities Finance GP1, a special purpose financing affiliate of Liberty Utilities Co., has a BBB (high) issuer rating from DBRS. The ratings indicate the agencies' assessment of the ability to pay the interest and principal of debt securities issued by such entities. The lower the rating, the higher the interest cost of the securities when they are sold. See "*Description of the Business – Credit Ratings*".

There can be no assurance that any of the Corporation'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. A downgrade in the Corporation's or Liberty Utilities Finance GP1's 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. If any of these ratings fall below investment grade (investment grade is defined as BBB- or above for S&P and BBB low or above for DBRS), the Corporation's ability to issue short-term debt or other securities, or to market those securities, would 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.

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 favorable terms, execute its acquisition and investment strategy, and finance its other activities upon favorable terms.

As of December 31, 2017, 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, funds available under its revolving 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 for at least the next twelve months. 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 favorable 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 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 will 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 that have less debt; 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 favorable exchange rate movement. In addition, any 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's existing credit facilities contain, and agreements that the Corporation may enter into in the future may contain, covenants that could restrict its financial flexibility.

The Corporation's existing credit facilities, and the credit facilities of its subsidiaries, contain covenants imposing certain requirements on the Corporation's business including covenants regarding the ratio of indebtedness to total capitalization. Furthermore, the Corporation's subsidiaries periodically issue long-term debt, historically consisting 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 its 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 the return 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, return 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 our results of operations and financial position.

Development by the Liberty Power Group of renewable power generation facilities in the United States depends in part on federal tax credits and other tax incentives. Although these incentives have been extended on multiple occasions, the most recent extension provides for a multi-year step-down. While recently enacted U.S. tax reform legislation did not make any changes to the multi-year step-down, there can be no assurance that there will not be further changes in the future. If these incentives are reduced or we are unable to complete construction on anticipated schedules, the reduced incentives may be insufficient to support continued development and construction of renewable power facilities in the United States or may result in substantially reduced benefits from facilities that we are committed to complete. In addition, the Liberty Power Group 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.

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 power purchase contracts, supply agreements and derivative financial instruments.

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 power purchase agreement is unable to perform, the Liberty Power 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 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 with respect to potential asset retirement obligations, which, if not accurate, may adversely affect its financial results.

The Corporation and its subsidiaries conduct periodic reviews of potential asset retirement obligations that may require recognition in the Corporation's financial statements. As part of this process, the Corporation and its subsidiaries consider requirements outlined in applicable operating permits, leases and other agreements, the probability of related agreements being extended, the ability to quantify such expense, the timing of incurring the potential expenses, as well as other factors in evaluating if such obligations exist and in estimating the fair value of such obligations. Inaccuracies in these estimates could result in the Corporation incurring significant expenses related to retirement obligations and adversely affect the Corporation's financial results.

The Corporation's asset retirement obligations mainly relate to legal requirements for: (i) removal of wind, solar and thermal facilities upon termination of land leases; (ii) cutting (disconnecting from the distribution system), purging (cleaning of natural gas and PCB contaminants) and capping gas mains within the gas distribution and transmission system when mains are retired in place, or disposing of sections of gas main when removed from the pipeline system; (iii) cleaning and removing storage tanks containing waste oil and other waste contaminants; and (iv) removing asbestos upon major renovation or demolition of structures and facilities.

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 would materially and adversely affect the Corporation.

The utility commissions in the states in which the Liberty Utilities Group operates regulate many aspects of its utility operations, including the rates that the Liberty Utilities 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. In addition, the electrical transmission system owned by the Liberty Power Group, which

is used to connect the Tinker Hydro Facility to the New Brunswick transmission network, is also subject to regulation by the New Brunswick Energy and Utilities Board.

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 transmission and distribution 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: Liberty Utilities Group's transmission or distribution 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 Liberty Power Group in the United States. The Liberty Power Group's facilities in the United States are required to meet the requirements of a "qualified 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 Liberty Power Group to maintain market-based rate authorization for certain facilities that currently have it would constitute a default under the facility's power purchase agreement and any project financing for such facility, and could materially and adversely affect the Corporation.

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. 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.

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 citing, construction, operation and decommissioning of wind 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 us 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 Liberty Utilities Group has historically recovered such costs through regulated customer rates, there can be no assurance that the Liberty Utilities Group will recover all or any part of such increased costs in future rate cases. The Liberty Power 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 result in 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 or regulation 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 currently, which may adversely affect the Corporation's ability to receive revenues or enforce its rights in connection with any operations 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 growth projects, thus limiting the Corporation's ability to control the operations of such projects. Any existing or new operations 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 in the local electricity 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 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 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 capital resources. Risks related to capital projects include schedule delays and project cost overruns. Capital expenditures at the utilities are generally approved by the respective regulators, however, 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 Corporation'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.

Once under construction, material delays or cost overruns could be incurred as a result of vendor or contractor 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 Liberty Power 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 would be adversely impacted.

The Liberty Power 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 power purchase agreements or to renew existing power purchase agreements 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 Liberty Power Group's power generation facilities is sold under long-term power purchase agreements, 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 termination or expiry of any such power purchase agreement, unless replaced or renewed on equally favorable 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 power purchase agreements is a risk factor in light of the competitive environment in which the Corporation operates. The Corporation expects the Liberty Power Group to continue to enter into power purchase agreements for the sale of its power, which power purchase agreements 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 power purchase agreements 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 complementary businesses and technologies are a part of the Corporation's overall business strategy. Because of the regulated nature of the business sectors in which the Corporation operates, nearly all acquisitions by the Corporation are subject to various regulatory approvals and, consequently, to the risks that such approvals may not be timely obtained or may impose unfavorable 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 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.

Failure to complete an acquisition may decrease investor confidence. In addition, the terms of an acquisition agreement may impose liability on the Corporation for failing to complete the acquisition, which in some cases may include liability where the reasons for failure to complete the acquisition are not entirely within the Corporation's control.

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 will not be realized. 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 sellers. 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 anticipated investment in Atlantica will be subject to the risk that 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.

Pursuant to the anticipated Atlantica investment, the Corporation will be investing in equity securities of Atlantica, a company that the Corporation does not control. In addition, subject to certain conditions and limited exceptions, the Corporation has agreed not to increase its interest in Atlantica above 41.5%. As a result, this anticipated investment will be 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 flow could be adversely affected.

Dividends declared and paid by Atlantica are made at the discretion of Atlantica's board of directors. The Corporation will 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 is 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 anticipated investment in Atlantica will expose it 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 jurisdictions where the Corporation does not currently operate, including Mexico, Peru, Chile, Brazil, Uruguay, Spain, Algeria and South Africa. The Corporation, through its anticipated investment in Atlantica, will be indirectly exposed to certain risks that are particular to Atlantica's business and 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 new jurisdictions, including in emerging markets, which could be subject to economic, social and political uncertainties; anti-bribery laws and substantial penalties and reputational damage from any non-compliance therewith; 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; reputational risk, including with respect to the reputation of Abengoa; termination or revocation of Atlantica's concession agreements or power purchase agreements; Abengoa's ability to meet its obligations under its agreements with Atlantica; 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 Liberty Utilities 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 Liberty Utilities 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 Liberty Utilities Group, and the Liberty Utilities Group believes that such compensation generally would reflect fair market value for any assets that are taken. 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 ability to execute its capital programs.

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 in certain areas is becoming increasingly common, which can challenge a utility's ability to execute its capital programs. The social acceptance by external stakeholders, including, in some cases, First Nations and other aboriginal peoples, local communities 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 will not have sole control over the projects that invests in with its joint venture partner, Abengoa, or over the revenues and certain decisions associated with those projects, which may limit the Corporation's flexibility with respect to these projects.

Despite having a 50% equity stake in AAGES, the joint venture involves risks, including, among others, a risk that Abengoa:

- may have economic or business interests or goals that are inconsistent with the Corporation's economic or business interests or goals;
- may take actions contrary to the Corporation's policies or objectives with respect to the Corporation's investments;
- may 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 AAGES and the Corporation;
- may have to give its consent with respect to certain major decisions;
- may become bankrupt, limiting its ability to meet calls for capital contributions and potentially making it more difficult to refinance or sell projects;
- may become engaged in a dispute with the Corporation that might affect the Corporation's ability to develop a project; or
- may have competing interests in the Corporation's markets that could create conflict of interest issues.

Further, the Corporation will not have sole control of certain major decisions relating to the projects that the Corporation pursues through AAGES, including, among others, decisions relating to funding and transactions with affiliates.

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.

The Corporation may from time to time dispose of businesses or assets that the Corporation no longer views as being strategic to the Corporation's continuing operations. 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.

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

The trading price and value of, and demand for, the Corporation's Common Shares will 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 businesses, operations, results and prospects;
- 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 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 Corporation's 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.

5. DIVIDENDS

Common Shares

The amount of dividends declared for each Common Share for fiscal 2015, 2016 and 2017 were U.S. $0.38, U.S. $0.41 and U.S. $0.47 respectively.

APUC follows a quarterly dividend schedule, subject to subsequent Board declarations each quarter. APUC's current quarterly dividend to shareholders is U.S. $0.1165 per common share or U.S. $0.4660 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".

Preferred Shares

On November 9, 2012, APUC issued 4,800,000 cumulative rate reset Series A preferred shares (the " **Series A Shares**"). For an initial six year period the 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 at an annual rate equal to $1.1250 per Series A Share. In each of 2015, 2016 and 2017, dividends of $1.1250 per Series A Share were paid.

On January 1, 2013, the Corporation issued 100 Series C Shares and exchanged such shares for the 100 Class B units of St. Leon LP, including 36 units held indirectly by the Senior Management. The Series C Shares provide dividends essentially identical to that expected from the Class B units. In 2015, 2016 and 2017, dividends paid to Series C preferred shareholders were $9,893, $8,528 and $7,922 per Series C Share respectively.

On March 5, 2014, APUC issued 4,000,000 cumulative rate reset Series D shares (the " **Series D Shares**"). For an initial five year period the 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 at

an annual rate equal to $1.250 per Series D Share. In 2015, 2016, and 2017, dividends of $1.25 per Series D Share were paid.

5.1 Dividend Reinvestment Plan

Under 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**". The Corporation has been a U.S. Securities and Exchange Commission registrant since 2009 and operates primarily in the United States.

As at December 31, 2017, APUC had 431,765,935 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, 2017, APUC had outstanding:

- 4,800,000 Series A Shares, yielding 4.5% annually for the initial six-year period ending on December 31, 2018;
- 100 Series C Shares; and
- 4,000,000 Series D Shares, yielding 5.0% annually for the initial five-year period ending on March 31, 2019.

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, 2018 and on December 31 every five years thereafter, are convertible upon the occurrence of certain events into cumulative floating rate preferred shares, Series B (the "**Series B Shares**"). The Series A Shares rank on a 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 $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. 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 a 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 $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.

Series C Shares

The Series C preferred 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 a 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 Preferred Shares are convertible into Common Shares and, if not so converted, will be automatically redeemed on June 19, 2031. Holders of the Series C Preferred Shares include a partnership controlled by Ian Robertson, Chief Executive Officer of the Corporation and a partnership controlled by Chris Jarratt, Vice Chairman 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, 2019 and on March 31 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 rank on a 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 $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 a 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 $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.

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 Series D Shares (and the Series B Shares and Series E Shares, respectively, into which they are convertible) will be entitled to one vote per share if APUC shall have failed to pay eight quarterly dividends on such shares. **The outstanding preferred shares do not have a right to participate in a take-over bid of the Common Shares of APUC.**

6.3 Convertible Debentures

On February 9, 2016, in connection with the Empire Acquisition, APUC completed the sale of the Debentures.

The Debentures will mature on March 31, 2026. The Debentures accrued interest at an annual rate of 5% per $1,000 dollars principal amount of Debentures until and including February 2, 2017, after which the interest rate became 0%.

At the option of the holders, each Debenture is convertible into Common Shares at any time prior to the earlier of maturity or redemption by APUC, at a conversion price of $10.60 per Common Share. APUC will issue up to 108,490,566 Common Shares on conversion of all of the Debentures. To date, a total of 108,384,716 Common Shares were issued, representing conversion into Common Shares of more than 99.9% of the Debentures. At maturity, APUC will have the right to pay the principal amount due in cash or in Common Shares. In the case of Common Shares, such shares will be valued at 95% of their weighted average trading price on the TSX for the 20 consecutive trading days ending five trading days preceding the maturity date.

6.4 Shareholders' Rights Plan

The shareholders' rights plan, as amended and restated in 2016 (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 twenty percent or more of the outstanding Common Shares without complying with the permitted bid provisions of the 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 fifty percent 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 fifty percent 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 ten 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 2019 or its termination under the terms of the of Amended and Restated Rights Plan. The Amended and Restated Rights Plan is similar to rights plans adopted by many other Canadian corporations.

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		
2017	**High ($)**	**Low ($)**	**Volume**	**High (US$)**	**Low (US$)**	**Volume**
January	11.48	11.15	37,934,616	8.79	8.33	347,242
February	12.29	11.33	28,660,212	9.35	8.68	355,634
March	12.98	11.98	24,143,635	9.71	9.00	323,442
April	13.05	12.57	17,211,371	9.74	9.38	242,782
May	13.98	12.90	19,040,345	10.35	9.44	282,999
June	14.35	13.26	16,660,457	10.80	10.21	273,733
July	13.70	12.90	18,919,660	10.85	10.00	316,009
August	13.83	13.10	12,252,860	11.02	10.33	327,519
September	13.59	12.91	17,566,633	11.20	10.50	447,560
October	14.145	13.18	18,200,984	11.21	10.56	500,870
November	14.40	12.99	30,208,784	11.34	10.13	813,669
December	14.33	13.86	15,101,341	11.22	10.80	472,775

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).

2017	High ($)	Low ($)	Volume
January	21.59	19.62	71,411
February	22.00	21.45	76,083
March	22.77	21.34	130,552
April	23.15	21.68	52,280
May	22.82	21.62	108,755
June	23.44	22.11	154,745
July	24.43	23.15	325,970
August	24.02	22.55	190,566
September	23.34	22.50	42,044
October	24.00	23.00	84,596
November	24.20	23.10	59,700
December	24.10	23.52	39,533

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).

2017	High ($)	Low ($)	Volume
January	24.32	22.90	133,516
February	24.42	23.80	114,078
March	24.62	22.95	86,538
April	24.50	23.73	19,168
May	24.40	23.16	48,047
June	24.59	23.40	55,076
July	25.00	24.22	163,059
August	24.92	23.63	46,036
September	25.05	23.81	40,283
October	25.30	25.00	33,432
November	25.98	25.14	24,310
December	25.50	24.90	96,914

7.2 Prior Sales

During the year ended December 31, 2017, there were no Series C Shares issued by APUC.

7.3 Escrowed Securities and Securities Subject to Contractual Restrictions on Transfer

There are no securities of APUC that are 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, and information on their history with APCo and APUC. Unless otherwise indicated, the individuals have been in their principal occupations for more than five years.

Name and Place of Residence	Principal Occupation	Served as Director or Officer of APUC from
CHRISTOPHER J. BALL Toronto, Ontario, Canada Age: 67	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, and is a recipient of the Clean Energy BC Lifetime Achievement Award.	Director of APUC since October 27, 2009 Trustee of APCo from October 22, 2002 until May 12, 2011
DAVID BRONICHESKI Oakville, Ontario, Canada Age: 58	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
CHRISTOPHER K. JARRATT Oakville, Ontario, Canada Age: 59	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 2010, 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. In 2009, Mr. Jarratt completed the Chartered Director program of the Directors College (McMaster University) and holds the certification of Ch. Dr. (Chartered Director). In addition, Mr. Jarratt was co-recipient of the 2007 Ernst & Young Entrepreneur of the Year finalist award.	Director of APUC since June 23, 2010
D. RANDY LANEY Farmington, Arkansas, USA Age: 63	D. Randy Laney was most recently Chairman of the Board of Empire District Electric Company since 2009. He joined the Board of Empire in 2003 serving as the Non-Executive Vice Chairman of the Board from 2008 to 2009 and Non-Executive Chairman of the Board from April 23, 2009 until APUC's acquisition of Empire on January 1, 2017. 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 including 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.	Director of APUC since February 1, 2017
KENNETH MOORE Toronto, Ontario, Canada Age: 59	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 has completed the Chartered Director program of the Directors College (McMaster University) and has the certification of Ch. Dir. (Chartered Director).	Director of APUC since October 27, 2009 Trustee of APCo from December 18, 1998 until November 10, 2010

Name and Place of Residence	Principal Occupation	Served as Director or Officer of APUC from
JEFF NORMAN Burlington, Ontario, Canada Age: 49	Jeff Norman is the Chief Development Officer of the Corporation, 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. Since 2008 the business development team has secured over 1 gigawatt of commercially secure renewable energy projects. Mr. Norman has over 24 years of experience and has reviewed the economic merits of hundreds of renewable energy projects located throughout North America.	Officer of APUC since May 25, 2015
DAVID PASIEKA Oakville, Ontario, Canada Age: 61	David Pasieka is the Chief Operating Officer of APUC's Liberty Utilities Group. As Chief Operating Officer, Mr. Pasieka is focused on acquiring and managing a portfolio of regulated water, natural gas and electrical companies throughout the United States. The focus of the portfolio is in the distribution, transmission, and generation sectors. Mr. Pasieka has global experience in strategy, sales, marketing, integration, operations and customer service. He has led many organizations while integrating people, process and technology to encourage the steady growth of the organizations. Mr. Pasieka holds a Bachelor of Science Degree from the University of Waterloo, Masters of Business Administration from the Schulich School of Business – York University and a Chartered Director designation from McMaster University.	Officer of APUC since September 1, 2011
IAN E. ROBERTSON Oakville, Ontario, Canada Age: 58	Ian Robertson is the Chief Executive Officer of the Corporation. 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 has completed the Chartered Director program of the Directors College (McMaster University), as well as a Global Professional Master of Laws degree from the University of Toronto and has the certification of Ch. Dir. (Chartered Director). Commencing in 2013, Mr. Robertson has served on the Board of Directors of the American Gas Association.	Director of APUC since June 23, 2010.
MASHEED SAIDI Dana Point, California, United States Age: 63	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 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 (P.E.).	Director of APUC since June 18, 2014
DILEK SAMIL Las Vegas, Nevada, United States Age: 62	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

Name and Place of Residence	Principal Occupation	Served as Director or Officer of APUC from
MIKE SNOW Markham, Ontario, Canada Age: 57	Mike joined APUC in 2011 and serves as Chief Operating Officer of APUC's Liberty Power Group. He is responsible for all aspects of strategy, business development, operations, asset management, human resources, and evaluating and reporting on growth and operational activities. Mike has led both industrial and consumer organizations focused on growth and international operations in Mexico, South America, and Asia, while driving culture change and building strong leadership teams. Mike holds a Bachelor of Science Degree in Math from Dalhousie University, a Bachelor of Engineering Degree (Mechanical) from the Technical University of Nova Scotia, and a Masters of Business Administration from the Ivey School of Business - Western University. Mike received his Chartered Director designation from McMaster University in 2014 and sits on the Board of Governors of the University of Ontario Institute of Technology.	Officer of APUC since July 4, 2011
MELISSA STAPLETON BARNES Age: 49 Carmel, Indiana, United States of America	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. Reporting directly to the CEO and Board of Directors, 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 Ethisphere - Business Ethics Leadership Alliance; CEB, Corporate Ethics Leadership Council; Conference Board, Global Council on Business Conduct; Healthcare Businesswomen's Association, and is a Licensed Attorney with the Indiana State Bar. Other board positions include The Center for the Performing Arts (Vice Chair), Visit Indy, The Children's Museum, and The Great American Songbook.	Director of APUC since June 9, 2016
GEORGE L. STEEVES Aurora, Ontario, Canada Age: 68	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 the Professional Engineering designation in Ontario and British Columbia. Additionally he has completed the Chartered Director program of the Directors College (McMaster University) and has the certification of Ch. Dir. (Chartered Director).	Director of APUC since October 27, 2009 Trustee of APCo from September 8, 1997 until May 12, 2011
JENNIFER TINDALE Campbellville, Ontario, Canada Age: 46	Jennifer Tindale is the Chief Legal Officer of the Corporation. 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 Age: 57	George Trisic is the Chief Administrative Officer and Corporate Secretary for the Corporation. 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 shared services for the Corporation including information technology, human resources, communications, and procurement, and is a well-regarded team builder and business partner. 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 has completed the Chartered Director program of the Directors College (McMaster University) and has the certification of Ch. Dir. (Chartered Director).	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.

As at March 7, 2018, the directors and executive officers of APUC, as a group, beneficially owned, directly or indirectly, or exercised control or direction over 5,091,086 Common Shares, representing less than one percent of the total number of Common Sha

res outstanding before giving effect to the exercise of options or warrants to purchase Common Shares held by such directors and executive officers. The statement as to the number of Common Shares beneficially owned, directly or indirectly, or over which control or direction is exercised by the directors and executive officers of APUC as a group is based upon information furnished by the 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 four directors of APUC, Mr. Ball (Chair), Ms. Stapleton Barnes, 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 charter for the Audit Committee is attached as Schedule F 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. 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 has also served as member of the Board of the Empire District Electric Company commencing in 2003 and as board Chair of that company from 2009 to 2016. Mr. Laney was also a member of the Audit Committee of the Empire District Electric Company 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	2017 Fees ($)	2016 Fees ($)	2015 Fees ($)
Audit Fees[1]	3,947,930	3,184,020	2,420,650
Audit-Related Fees[2]	100,235	113,414	98,835
Other Tax Fees[3]	252,535	269,631	395,100

[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 and translation services.

[3] For tax advisory and planning services.

8.3 Corporate Governance, Risk and Compensation Committees

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

In 2017, 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 directors have also put in place a Compensation Committee, currently comprised of three directors of APUC, Ms. Samil (Chair), 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 Potential Material Conflicts of Interest

Other than as disclosed elsewhere in this AIF (see "*Description of the Business - Related Party Transactions*"), to the knowledge of the directors and executive officers of APUC 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

Except as disclosed elsewhere in this AIF, there are no legal proceedings involving the Corporation that were material in 2017 or that the Corporation knows to be contemplated.

9.2 Regulatory Actions

Except as disclosed elsewhere in this AIF, during the financial year ended December 31, 2017, there have been:

(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; or

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

Except as disclosed elsewhere in this AIF, the only regulatory action involving the Corporation that was material in 2017 is as follows:

(i) Mountain Water Condemnation

On May 6, 2014, the City of Missoula, Montana filed a lawsuit against Mountain Water Company and its prior indirect owner Carlyle Infrastructure Partners, L.P. ("**Carlyle**"), seeking to condemn the assets of Mountain Water. The case went to trial on the right to take or "necessity" phase in March, 2015. The District Court issued a Preliminary Order of Condemnation on June 15, 2015, finding that the City had established the right to take the assets of Mountain Water. Mountain Water filed an appeal with the Montana Supreme Court. The case then proceeded to a trial on valuation before three Commissioners. On November 17, 2015, the Commissioners issued a report finding that the "fair market value" of the condemned property as of May 6, 2014 was U.S. $88.6 million. On August 2, 2016, the Supreme Court of Montana upheld the District Court's decision, permitting the City of Missoula to proceed with the condemnation of Mountain Water's assets.

On December 22, 2015, certain developers filed a lawsuit in Montana District Court against the City of Missoula and Mountain Water seeking resolution of claims to a portion of the condemnation award on the basis that certain of the assets being condemned had been funded by such parties. On February 21, 2017, the court in that case recognized an equitable lien on such assets in favor of the developers and ordered that a portion of the condemnation award, if and when paid, be paid by the City of Missoula to the court for direct payment to the developers.

On or about June 5, 2017, Mountain Water, Liberty Utilities Co. and the City of Missoula entered into a Settlement Agreement and Release of Claims, resolving certain issues in the event that the City acquired possession of Mountain Water's assets, and contingent upon settlement of the developer lawsuit. The settlement agreement was approved by the condemnation court in hearings on June 15 and June 22, 2017, and a final order of condemnation was issued on June 22, 2017. The developer lawsuit was dismissed on June 30, 2017. On June 22, 2017, the City of Missoula paid the condemnation judgment, including amounts owed to Mountain Water and amounts required to be paid to the developers. The City of Missoula took possession of Mountain Water's assets on that date. Carlyle and Mountain Water have appealed certain elements of the final order of condemnation including, among other issues, recovery of post-summons interest and attorney's fees.

(ii) Apple Valley Condemnation

On January 7, 2016, the Town of Apple Valley filed a lawsuit seeking to condemn the utility assets of Liberty Utilities (Apple Valley Ranchos Water) Corp. The Town seeks to condemn the utility assets of Apple Valley and to acquire a determination of fair market value. In the first phase of the case, the Court will determine the necessity of the taking by the Town. If the Court determines that necessity has been established, in a second phase, a jury will determine the fair market value of the assets being condemned. The condemnation case is currently proceeding in discovery. Resolution of the condemnation proceedings is expected to take two to three years. The Court has been briefed on a related California Environmental Quality Act (CEQA) lawsuit (challenging the Town's compliance with CEQA in connection with the proposed condemnation) and heard oral argument in December 2017. The Court issued the CEQA decision on February 9, 2018 and denied Liberty Utilities (Apple Valley Ranchos Water) Corp.s CEQA claim. As a result, the condemnation case will proceed. The Court has set a scheduling conference for the condemnation case in March, 2018 to potentially set a trial date on the first phase of the condemnation action.

10. INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

Other than as disclosed elsewhere in this AIF, no director, executive officer or principal holder of 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, Montréal, Vancouver, Calgary, and Halifax.

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

12. MATERIAL CONTRACTS

Except for certain contracts entered into in the ordinary course of business of the Corporation, the contracts described below are the only contracts entered into by the Corporation during 2017 (or prior to 2017 in the case of contracts that are still in effect) that are material to the Corporation:

(a) Atlantica Share Purchase Agreement: APUC entered into a sale and purchase agreement dated November 2, 2017, as amended, with ACIL Luxco 1, S.A. and Abengoa providing for the purchase by APUC from ACIL Luxco 1, S.A. of a 25% equity interest in Atlantica for a total purchase price of approximately U.S. $608 million plus a contingent payment payable two years after closing, subject to certain conditions. See *"General Development of the Business – Three Year History and Significant Acquisitions – Fiscal 2017"* .

(b) Underwriting Agreement: Underwriting Agreement dated November 3, 2017, between APUC and Scotia Capital Inc., CIBC World Markets Inc. and TD Securities Inc. as co-lead underwriters, in connection with an offering of Common Shares which closed on November 10, 2017. See "*General Development of the Business – Fiscal 2017 – Bought Deal Offering of Common Shares"* .

(c) **APCo debentures:** APCo Trust Indenture between APCo and BNY Trust Company of Canada dated July 25, 2011 providing for the issuance of senior unsecured debentures, as supplemented from time to time, including by the Fourth Supplemental Trust Indenture dated January 17, 2017 providing for the issuance of $300,000,000 4.09% senior unsecured debentures due February 17, 2027.

(d) **U.S. Debt Private Placements**: Trust Indenture dated July 2, 2012 between Liberty Utilities Finance GP 1 and The Bank of New York Mellon providing for the creation and issuance of senior unsecured debentures, as supplemented from time to time.

(e) **Empire Acquisition**: Agreement and Plan of Merger, dated as of February 9, 2016, by and among Empire, Liberty Utilities (Central) Co., and Liberty Utilities (Sub) Corp. pursuant to which Liberty Utilities (Central) Co. agreed to acquire Empire and (indirectly) its subsidiaries by merger of Liberty Sub Corp. with and into Empire. APUC guaranteed the payment and performance of all obligations of Liberty Utilities (Central) Co. under the Agreement and Plan of Merger pursuant to a Guarantee dated as of February 9, 2016, by APUC in favour of Empire.

(f) **Underwriting Agreement**: Underwriting Agreement dated February 15, 2016, between LU Canada, as the selling debenture holder, and CIBC World Markets Inc. and Scotia Capital Inc. as co-lead underwriters, providing for the issuance and sale of not less than $1,000,000,000 and up to $1,150,000,000 principal amount of Debentures in connection with the Debenture Offering.

(g) **Trust Indenture**: Trust Indenture dated as of March 1, 2016, between APUC and CST Trust Company, as trustee, providing for the creation and issuance of up to $1,150,000,000 principal amount of Debentures in connection with the Debenture Offering, as supplemented by a supplemental trust indenture dated January 31, 2017.

13. INTERESTS OF 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, 2017, which are available on SEDAR at www.sedar.com and on EDGAR at www.sec.gov/edgar.

SCHEDULE A

Renewable – Selected Hydroelectric, Solar and Wind Facilities

Generating Facility/Owner	Generating Capacity (MW)	Location	Electricity Purchaser	PPA Expiry Year
Facility: Dickson Dam Hydro Facility **Owner:** Algonquin Power Operating Trust	15	Innisfail, Alberta	AESO	N/A
Facility: Tinker Hydro Facility **Owner**: Algonquin Tinker Gen Co.	34	Perth-Andover, New Brunswick	Algonquin Energy Services Inc. Town of Perth-Andover	Perth-Andover Contract through 2031
Facility: Bakersfield I Solar Facility **Owner**: Algonquin SKIC20 Solar, LLC	20	Kern County, California	Pacific Gas & Electric Company	2035
Facility: Great Bay Solar Facility **Owner**: Great Bay Solar I, LLC	75	Somerset County, Maryland	Under Development - U.S. General Services Administration	2028 (10 years after COD)
Facility: St. Leon Wind Facility **Owner**: St. Leon Wind Energy LP	103.9	St. Leon, Manitoba	Manitoba Hydro	2026 + one 5 year extension
Facility: Amherst Island Wind Project **Owner**: Windlectric Inc.	75	Stella, Ontario	Under Development - IESO	2038 (20 years after COD)
Facility: Blue Hill Wind Project **Owner**: Blue Hill Wind Energy Project Partnership	177	Lawtonia, Saskatchewan	Under Development - SaskPower	2044/5 (25 years after COD)
Facility: Minonk Wind Facility **Owner**: Minonk Wind, LLC	200	Minonk, Illinois	PJM North Illinois	2023 [1]
Facility: Senate Wind Facility **Owner:** Senate Wind, LLC	150	Graham, Texas	ERCOT North markets	2027 [1]
Facility: Sandy Ridge Wind Facility **Owner:** Sandy Ridge Wind, LLC	50	Tyrone, Pennsylvania	PJM West	2023 [1]

Generating Facility/Owner	Generating Capacity (MW)	Location	Electricity Purchaser	PPA Expiry Year
Facility: Shady Oaks Wind Facility **Owner:** GSG 6, LLC	109.5	Lee County, Illinois	Commonwealth Edison	2032
Facility: Odell Wind Facility **Owner**: Odell Wind Farm, LLC.	200	Cottonwood, Jackson, Martin and Watonwan Counties, Minnesota	Northern States Power	2036
Facility: Deerfield Wind Facility **Owner**: Deerfield Wind Energy, LLC	150	Central Michigan	Wolverine Power Supply Co-operative	2037

[1] The Corporation currently has hedge agreements in place in respect of each facility. See “Description of the Business – Liberty Power Group – Description of Operations – Wind Power Generating Facilities – Material Facilities”.

SCHEDULE B

Selected Thermal – Biomass, Cogeneration, and Diesel Facilities

Generating Facility/Owner	Generating Capacity (MW)	Location	Electricity Purchaser	PPA Expiry Year	Lease Expiry Year
Facility: Sanger Facility **Owner**: Algonquin Power Sanger LLC	56	Sanger, California	Pacific Gas & Electric Company	2021	Owned
Facility: Windsor Locks Facility **Owner**: Algonquin Power Windsor Locks LLC	71	Windsor Locks, Connecticut	ISO New England Ahlstrom Corporation	2027	2027

SCHEDULE C

Selected Wastewater and Water Distribution Facilities

Utility	Owner	Location	Type of Utility	Rates[1]
LPSCo System	Liberty Utilities (Litchfield Park Water & Sewer) Corp.	Litchfield, Park, Arizona	Wastewater Water Distribution	Pursuant to ACC docket 74437
Pine Bluff Water System	Liberty Utilities (Pine Bluff Water) Inc.	Pine Bluff, Arkansas	Water Distribution	Pursuant to APSC docket No. 14-020-U
Liberty Park Water System	Liberty Utilities (Park Water) Corp.	Downey, California	Water Distribution	Pursuant to CPUC decision 16-01-009
Apple Valley Water System	Liberty Utilities (Apple Valley Ranchos Water) Corp.	Apple Valley, California	Water Distribution	Pursuant to CPUC decision 15-11-030
Empire District Water System	The Empire District Electric Company	Joplin, Missouri	Distribution	MO – WR-2012-0300

[1] See www.libertyutilities.com for complete rate tariffs.

SCHEDULE D

Selected Electrical Distribution Facilities

Utility	Owner	Location	Type of Utility	Rates[1]
CalPeco Electric System	Liberty Utilities (CalPeco Electric) LLC	Lake Tahoe, California	Electricity Distribution	Rates pursuant to CPUC decision 16-12-024
Granite State Electric System	Liberty Utilities (Granite State Electric) Corp	Salem, New Hampshire	Electricity Distribution	Rates pursuant to NHPUC docket DE 13-063, Order 25,638 and docket DE 16-383, Order 26,005
Empire District Electric System	The Empire District Electric Company	Joplin, Missouri	Electricity Generation, Transmission & Distribution	MO - ER-2016-0023 AR - 13-111-U KS - 11-EPDE-856-RTS OK - PUD 201600468

[1] See www.libertyutilities.com for complete rate tariffs.

SCHEDULE E

Selected Natural Gas Distribution Facilities

Utility	Owner	Location	Type of Utility	Rates[1]
EnergyNorth Gas System	Liberty Utilities (EnergyNorth Natural Gas) Corp.	Londonderry, New Hampshire	Natural Gas Distribution	Rates pursuant to NHPUC docket DG 14-180, Order 25,797
Peach State Gas System	Liberty Utilities (Peach State Natural Gas) Corp.	Columbus, Gainesville, Georgia	Natural Gas Distribution	Rates pursuant to GPSC docket #34734 Document #166,984
New England Gas System	Liberty Utilities (New England Natural Gas Company) Corp.	Fall River, North Attleboro, Plainville, Westport, Swansea, Somerset, Massachusetts	Natural Gas Distribution	Rates pursuant to D.P.U 15-75
Midstates Gas System	Liberty Utilities (Midstates Natural Gas) Corp.	Salem, Virden, Vandalia, Xenia, Metropolis, Illinois Keokuk, Iowa Jackson, Sikeston, Butler, Kirksville, Hannibal, Missouri	Natural Gas Distribution	Rates pursuant to ICC decision IL-16-0401 Rates pursuant to IUB decision RPU-2016-0003 Rates pursuant to MOPSC decision GR-2014-0152
New Hampshire Gas System	Liberty Utilities (EnergyNorth Natural Gas) Corp.	Keene, New Hampshire	Propane Gas Distribution	Rates pursuant to NHPUC docket DG 09-038
Empire District Gas System	The Empire District Gas Company	Joplin, Missouri	Natural Gas Distribution	MO - GR-2009-0434

[1] See www.libertyutilities.com for complete rate tariffs.

SCHEDULE F

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 1, 2018.

SCHEDULE G

GLOSSARY OF TERMS

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

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

"**AAGES Preferred Shares**" has the meaning ascribed thereto under *"Description of the Business – Portfolio Investments"*.

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

"**ACC**" means the Arizona Corporation Commission.

"**ADEQ**" means Arizona Department of Environmental Quality.

"**Adjusted EBITDA**" has the meaning ascribed thereto under "*Caution Concerning Forward-looking Statements and Forward-looking Information*".

"**AESO**" means Alberta Electric System Operator.

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

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

"**Amherst Island Wind Project**" has the meaning ascribed thereto under "*Description of the Business – Liberty Power Group – Business Development – Current Development or Construction Projects*".

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

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

"**Apple Valley**" has the meaning ascribed thereto under *"Corporate Structure - Intercorporate Relationships"*.

"**Apple Valley Water System**" means the Apple Valley Ranchos water facility in Apple Valley, California.

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

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

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

"**AY Shares**" has the meaning ascribed thereto under *"Description of the Business – Portfolio Investments"*.

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

“**Bakersfield II Solar Facility**” means the 10 MW Bakersfield solar generating facility in California .

"**Blue Hill Wind Project**" has the meaning ascribed thereto under "*Description of the Business – Liberty Power Group – Business Development – Current Development or Construction Projects*".

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

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

"**CAISO**" means California Independent System Operation.

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

"**Carlyle**" has the meaning ascribed thereto under the heading "*Legal Proceedings and Regulatory Actions - Regulatory Actions – Mountain Water Condemnation*".

"**CEQA**" means California Environmental Quality Act.

"**COD**" means commercial operation date.

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

"**Cornwall Solar Facility**" means the solar generating facility in Cornwall, Ontario.

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

"**CPCN**" means Certificate of Public Convenience and Necessity.

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

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

"**Debentures**" has the meaning ascribed thereto under *"General Development of the Business – Three Year History and Significant Acquisitions – Fiscal 2016 - Corporate".*

"**Debenture Offering**" has the meaning ascribed thereto under *"General Development of the Business – Three Year History and Significant Acquisitions – Fiscal 2016 - Corporate".*

"**Default Service**" has the meaning ascribed thereto under *"Description of the Business - Liberty Utilities Group - Electric Distribution Systems - Material Facilities"*.

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

"**Dickson Dam Hydro Facility**" means the Dickson hydroelectric generating facility in Alberta.

"**ECAC**" means energy cost adjustment clause.

"**EDG**" The Empire District Gas Company.

“**Empire**” has the meaning ascribed thereto under *“Corporate Structure - Intercorporate Relationships”*.

“**Empire Acquisition**” has the meaning ascribed thereto under *"General Development of the Business – Three Year History and Significant Acquisitions – Fiscal 2016 - Corporate"*.

"**Empire Acquisition Facility**" has the meaning ascribed thereto under *"General Development of the Business – Three Year History and Significant Acquisitions – Fiscal 2016 - Corporate".*

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

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

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

"**EUA**" means Electric Utilities Act (Alberta).

"**EWGs**" has the meaning ascribed thereto under *"Description of the Business – Liberty Power Group - Regulatory Regimes-Power Generation - United States".*

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

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

"**FPA**" has the meaning ascribed thereto under *"Description of the Business - Liberty Power Group - Regulatory Regimes-Power Generation - United States".*

"**Full PTC Projects**" has the meaning ascribed thereto under *"General Development of the Business - Three Year History and Significant Acquisitions - Fiscal 2016 - Liberty Power Group Highlights".*

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

"**GAF**" has the meaning ascribed thereto under "*Description of the Business – Liberty Utilities Group – Description of Operations – Natural Gas Distribution Systems – Material Facilities*".

"**GRAM**" means the Georgia Rate Adjustment Mechanism.

"**Great Bay Solar Project**" means the Great Bay solar facility in Somerset County, Maryland.

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

"**Hydro-Québec**" means Hydro-Québec Distribution.

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

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

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

"**JPMVEC**" has the meaning ascribed thereto under "*Description of the Business – Liberty Power Group – Description of Operations – Wind Power Generating Facilities – Material Facilities*".

"**KCC**" means State Corporation Commission of the State of Kansas.

"**Liberty Park Water**" has the meaning ascribed thereto under *"Corporate Structure - Intercorporate Relationships"*.

"**Liberty Park Water System**" has the meaning ascribed thereto under *"General Development of the Business - Three Year History and Significant Acquisitions - Fiscal 2016 - Liberty Utilities Group"*.

"**Long Sault Hydro Facility**" means the Long Sault rapids hydroelectric generating facility.

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

"**LU Canada**" has the meaning ascribed thereto under *"Corporate Structure - Intercorporate Relationships"*.

"**Luning Facility**" has the meaning ascribed thereto under *"General Development of the Business – Three Year History and Significant Acquisitions – Fiscal 2017 – Liberty Utilities Group".*

"**Manitoba Hydro**" means the Manitoba Hydro-Electric Board.

"**MBR Authority**" has the meaning ascribed thereto under *"Description of the Business - Liberty Power Group - Regulatory Regimes-Power Generation - United States".*

"**MD&A**" has the meaning ascribed thereto under "*Caution Concerning Forward-looking Statements and Forward-looking Information"*.

"**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.

"**Morse Wind Facility**" means the Morse wind facility in Saskatchewan.

"**MPSC**" means Missouri Public Services Commission.

"**MW**" means megawatt.

"**MWh**" means megawatt hours.

"**NB Power**" means New Brunswick Power Corporation.

"**NBSO**" means New Brunswick System Operator.

"**Net Energy Sales**" has the meaning ascribed thereto under "*Caution Concerning Forward-looking Statements and Forward-looking Information*".

"**Net Utility Sales**" has the meaning ascribed thereto under "*Caution Concerning Forward-looking Statements and Forward-looking Information*".

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

"**NHPUC**" means the New Hampshire Public Utilities Commission.

"**NERC**" means the North American Electric Reliability Corporation.

"**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 .

"**OEB**" means the Ontario Energy Board.

"**OEFC**" means Ontario Electric Financial Corporation.

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

"**OPG**" means Ontario Power Generation Inc.

"**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 – Liberty Power Group – Description of Operations – Wind Power Generating Facilities – Material Facilities*".

"**PTC**" has the meaning ascribed thereto under *"General Development of the Business - Three Year History and Significant Acquisitions - Fiscal 2016 - Liberty Power Group".*

"**PUHCA**" has the meaning ascribed thereto under *"Description of the Business - Liberty Power Group - Regulatory Regimes-Power Generation - United States".*

"**QFs**" has the meaning ascribed thereto under *"Description of the Business - Liberty Power Group - Regulatory Regimes-Power Generation - United States".*

"**REC**" means renewable energy credits.

"**Red Lily Wind Facility**" has the meaning ascribed thereto under *"General Development of the Business - Three Year History and Significant Acquisitions - Fiscal 2016 - Liberty Power Group".*

"**Reinvestment Plan**" has the meaning ascribed thereto under *"General Development of the Business – Three Year History and Significant Acquisitions – Fiscal 2017 - Corporate".*

"**RPS**" means renewable portfolio standards.

"**RTO**" means regional transmission organization.

"**S&P**" means Standard & Poor's Financial Services LLC.

"**Saint-Damase Wind Facility**" means the Saint-Damase wind facility.

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

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

"**Series A Shares**" has the meaning ascribed thereto under "*Dividends - 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 *"Description of Capital Structure – Preferred Shares".*

"**Series D Shares**" has the meaning ascribed thereto under *"Dividends - Preferred Shares".*

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

"**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 – Liberty Utilities Group".*

"**SPP**" means Southwest Power Pool.

"**SPP IM**" has the meaning ascribed thereto under "*Enterprise Risk Factors – Risk Factors Relating to Operations*".

"**St. Leon II Wind Facility**" means the 16.5 MW wind facility located at St. Leon, Manitoba .

"**St. Leon LP**" has the meaning ascribed thereto under *"Corporate Structure - Intercorporate Relationships - Subsidiaries".*

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

"**SWRCB**" means the Division of Drinking Water of the California State Water Resources Control Board.

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

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

"**Val-Éo Wind Project**" "has the meaning ascribed thereto under "*Description of the Business – Liberty Power Group – Business Development – Current Development or Construction Projects*".

"**Windsor Locks Facility**" has the meaning ascribed thereto under the heading *"Description of the Business - Liberty Power Group - Description of Operations - Thermal (Cogeneration) Electric Generating Facilities - Material Facilities"*.

Consolidated Financial Statements of
Algonquin Power & Utilities Corp.
For the years ended December 31, 2017 and 2016

MANAGEMENT'S REPORT

Financial Reporting

The preparation and presentation of the accompanying Consolidated Financial Statements, MD&A and all financial information in the Financial Statements are the responsibility of management and have been approved by the Board of Directors. The 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 financial statements for external purposes in accordance with generally accepted accounting principles.

Management assessed the effectiveness of the Company's internal control over financial reporting as of December 31, 2017, 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, 2017.

During the year ended December 31, 2017, APUC acquired The Empire District Electric Company and its subsidiaries ("Empire"). The financial information for this acquisition is included in note 3(a) to the consolidated financial statements. As permitted by National Instrument 52-109 and published guidance of the U.S. Securities and Exchange Commission (SEC), management's assessment of and conclusion on the effectiveness of internal control over financial reporting did not include the internal controls of Empire, which are included in the 2017 consolidated financial statements of Algonquin Power and Utilities Corp. and constituted $3,130,150 of total assets as at December 31, 2017 and $812,289 of revenues for the year then ended.

March 7, 2018

/s/ Ian Robertson
Chief Executive Officer

/s/ David Bronicheski
Chief Financial Officer

REPORT OF 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 financial statements of Algonquin Power & Utilities Corp. (the "Company"), which comprise the consolidated balance sheets as at December 31, 2017 and December 31, 2016, the consolidated statements of operations, comprehensive income/(loss), equity and cash flows for the years then ended, and the related notes, comprising a summary of significant accounting policies and other explanatory information (collectively referred to as the "consolidated financial statements").

In our opinion, the consolidated financial statements present fairly, in all material respects, the consolidated financial position of the Company as at December 31, 2017 and December 31, 2016, and its consolidated financial performance and its consolidated cash flows for the years then ended in accordance with United States 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, 2017, based on the criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO"), and our report dated March 7, 2018 expressed an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

Basis for Opinion

Management's Responsibility for the Consolidated Financial Statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with United States generally accepted accounting principles, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards and 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 from material misstatement, whether due to error or fraud. Those standards also require that we comply with ethical requirements, including independence. We are required to be independent with respect to the Company in accordance with the ethical requirements that are relevant to our audit of the consolidated financial statements in Canada, the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB. We are a public accounting firm registered with the PCAOB.

An audit includes performing procedures to assess the risks of material misstatements of the consolidated financial statements, whether due to error or fraud, and performing procedures to respond to those risks. Such procedures included obtaining and examining, on a test basis, audit evidence regarding the amounts and disclosures in the consolidated financial statements. The procedures selected depend on our judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, we consider internal control relevant to the Company's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances.

An audit also includes evaluating the appropriateness of accounting policies and principles used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a reasonable basis for our audit opinion.

/s/ Ernst & Young LLP

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

Toronto, Canada

March 7, 2018

REPORT OF 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, 2017, based on criteria established in Internal Control-Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (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, 2017, based on the COSO criteria.

We also have audited, in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States) ("PCAOB"), the consolidated balance sheets as at December 31, 2017 and December 31, 2016, the consolidated statements of operations, comprehensive income, equity and cash flows for the years then ended, and the related notes, comprising a summary of significant accounting policies and other explanatory information and our report dated March 7, 2018 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 ethical requirements that are relevant to our audit of the consolidated financial statements in Canada, 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.

As indicated under the heading Internal Controls over Financial Reporting 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 Empire District Electric Corp. and its subsidiaries ("Empire"), which are included in the 2017 consolidated financial statements of the Company and constituted $3,130,150 of total assets as at December 31, 2017 and $812,289 of revenues, for the year then ended. Our audit of internal control over financial reporting of Algonquin Power and Utilities Corp. also did not include an evaluation of the internal control over financial reporting of Empire.

/s/ Ernst & Young LLP

Toronto, Canada

March 7, 2018

Algonquin Power & Utilities Corp.
Consolidated Balance Sheets

(thousands of Canadian dollars)

	December 31, 2017	December 31, 2016
ASSETS		
Current assets:		
Cash and cash equivalents	$ 54,550	$ 110,417
Accounts receivable, net (note 4)	306,872	189,658
Fuel and natural gas in storage (note 1(h))	55,718	21,625
Supplies and consumables inventory	56,546	15,568
Regulatory assets (note 7)	83,508	48,440
Prepaid expenses	38,896	26,562
Derivative instruments (note 25)	20,196	76,631
Other assets (note 12)	8,919	2,951
	625,205	491,852
Property, plant and equipment, net (note 5)	7,909,493	4,889,946
Intangible assets, net (note 6)	64,108	64,989
Goodwill (note 6)	1,196,234	306,641
Regulatory assets (note 7)	467,626	243,524
Derivative instruments (note 25)	67,888	74,553
Long-term investments (note 8)	84,467	105,433
Deferred income taxes (note 20)	76,972	30,005
Restricted cash (note 1(f))	19,995	2,026,183
Other assets (note 12)	21,647	16,334
	$ 10,533,635	$ 8,249,460

Algonquin Power & Utilities Corp.
Consolidated Balance Sheets

(thousands of Canadian dollars)

	December 31, 2017	December 31, 2016
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable	$ 150,426	$ 90,592
Accrued liabilities	351,441	308,318
Dividends payable (note 17)	63,283	38,973
Regulatory liabilities (note 7)	47,278	47,769
Long-term debt (note 9)	15,511	10,075
Other long-term liabilities and deferred credits (note 13)	57,586	43,157
Derivative instruments (note 25)	17,721	4,178
Other liabilities	4,359	3,487
	707,605	546,549
Long-term debt (note 9)	3,847,785	3,903,340
Convertible debentures (note 14)	1,218	358,619
Regulatory liabilities (note 7)	677,778	134,965
Deferred income taxes (note 20)	499,819	288,139
Derivative instruments (note 25)	68,769	104,647
Pension and other post-employment benefits obligation (note 10)	210,994	147,845
Other long-term liabilities (note 13)	285,106	232,449
Preferred shares, Series C (note 11)	17,396	17,552
	5,608,865	5,187,556
Redeemable non-controlling interest (note 19)	52,128	29,434
Equity:		
Preferred shares (note 15(b))	213,805	213,805
Common shares (note 15(a))	3,713,037	1,972,203
Additional paid-in capital	43,204	38,652
Deficit	(617,836)	(556,024)
Accumulated other comprehensive income (note 16)	56,820	254,927
Total equity attributable to shareholders of Algonquin Power & Utilities Corp.	3,409,030	1,923,563
Non-controlling interests (note 19)	756,007	562,358
Total equity	4,165,037	2,485,921
Commitments and contingencies (note 23)		
Subsequent events (notes 9 and 15(a)(iii))		
	$ 10,533,635	$ 8,249,460

See accompanying notes to consolidated financial statements

Algonquin Power & Utilities Corp.
Consolidated Statements of Operations

(thousands of Canadian dollars, except per share amounts)	Year ended December 31	
	2017	**2016**
Revenue		
Regulated electricity distribution	$ 989,221	$ 228,097
Regulated gas distribution	493,208	405,735
Regulated water reclamation and distribution	181,851	181,655
Non-regulated energy sales	282,558	243,149
Other revenue	30,971	37,382
	1,977,809	1,096,018
Expenses		
Operating expenses	598,658	333,001
Regulated electricity purchased	288,183	119,825
Regulated gas purchased	184,523	142,003
Regulated water purchased	12,310	12,227
Non-regulated energy purchased	25,384	21,260
Administrative expenses	64,466	46,349
Depreciation and amortization	326,447	186,899
Loss (gain) on foreign exchange	373	(436)
	1,500,344	861,128
Operating income	477,465	234,890
Interest expense on long-term debt and others	184,993	73,962
Interest expense on convertible debentures and amortization of acquisition financing (notes 9(b) and 14)	17,638	57,630
Interest, dividend, equity and other income	(11,989)	(10,573)
Other losses (gains) (note 23(a))	632	(11,818)
Acquisition-related costs	62,777	12,028
Gain on derivative financial instruments (note 25(b)(iv))	(2,626)	(15,849)
	251,425	105,380
Earnings before income taxes	226,040	129,510
Income tax expense (note 20)		
Current	9,908	8,461
Deferred	85,286	28,675
	95,194	37,136
Net earnings	130,846	92,374
Net effect of non-controlling interests (note 19)	62,248	38,550
Net earnings attributable to shareholders of Algonquin Power & Utilities Corp.	$ 193,094	$ 130,924
Series A and D Preferred shares dividend (note 17)	10,400	10,400
Net earnings attributable to common shareholders of Algonquin Power & Utilities Corp.	$ 182,694	$ 120,524
Basic net earnings per share (note 21)	$ 0.48	$ 0.44
Diluted net earnings per share (note 21)	$ 0.47	$ 0.44

See accompanying notes to consolidated financial statements

Algonquin Power & Utilities Corp.
Consolidated Statements of Comprehensive Income

(thousands of Canadian dollars)	Year ended December 31	
	2017	2016
Net earnings	$ 130,846	$ 92,374
Other comprehensive income (loss):		
Foreign currency translation adjustment, net of tax recovery of $219 and $nil, respectively (notes 1(v), 25(b)(iii) and 25(b)(iv))	(256,067)	(67,855)
Change in fair value of cash flow hedges, net of tax expense of $756 and $18,109, respectively (note 25(b)(ii))	1,909	26,754
Change in value of available-for-sale investments	(141)	213
Change in pension and other post-employment benefits, net of tax expense of $717 and $1,433, respectively (note 10)	525	2,252
Other comprehensive loss, net of tax	(253,774)	(38,636)
Comprehensive (loss) income	(122,928)	53,738
Comprehensive loss attributable to the non-controlling interests	(117,915)	(45,376)
Comprehensive income (loss) attributable to shareholders of Algonquin Power & Utilities Corp.	$ (5,013)	$ 99,114

See accompanying notes to consolidated financial statements

Algonquin Power & Utilities Corp.
Consolidated Statement of Equity

(thousands of Canadian dollars)
For the year ended December 31, 2017

	Algonquin Power & Utilities Corp. Shareholders					Non-controlling interests	Total
	Common shares	Preferred shares	Additional paid-in capital	Accumulated deficit	Accumulated OCI		
Balance, December 31, 2016	$ 1,972,203	$ 213,805	$ 38,652	$ (556,024)	$ 254,927	$ 562,358	$ 2,485,921
Net earnings (loss)	—	—	—	193,094	—	(62,248)	130,846
Redeemable non-controlling interests not included in equity (note 19)	—	—	—	—	—	13,400	13,400
Other comprehensive loss	—	—	—	—	(198,107)	(55,667)	(253,774)
Dividends declared and distributions to non-controlling interests	—	—	—	(205,439)	—	(5,055)	(210,494)
Dividends and issuance of shares under dividend reinvestment plan (note 15(a)(iii))	47,470	—	—	(47,470)	—	—	—
Common shares issued pursuant to public offering, net of costs (note 15(a)(i))	558,083	—	—	—	—	—	558,083
Common shares issued upon conversion of convertible debentures (note 14)	1,114,688	—	—	—	—	—	1,114,688
Common shares issued pursuant to share-based awards (note 15(c))	20,593	—	(6,527)	(1,997)	—	—	12,069
Share-based compensation (note 15(c))	—	—	11,079	—	—	—	11,079
Contributions received from non-controlling interests (notes 3(c), 3(g) and 8(b))	—	—	—	—	—	303,219	303,219
Balance, December 31, 2017	$ 3,713,037	$ 213,805	$ 43,204	$ (617,836)	$ 56,820	$ 756,007	$ 4,165,037

Algonquin Power & Utilities Corp.
Consolidated Statement of Equity

(thousands of Canadian dollars)
For the year ended December 31, 2016

	Algonquin Power & Utilities Corp. Shareholders							
	Common shares	Preferred shares	Subscription receipts	Additional paid-in capital	Accumulated deficit	Accumulated OCI	Non-controlling interests	Total
Balance, December 31, 2015	$ 1,808,894	$ 213,805	$ 110,503	$ 38,241	$ (523,116)	$ 286,737	$ 356,800	$ 2,291,864
Net earnings (loss)	—	—	—	—	130,924	—	(38,550)	92,374
Redeemable non-controlling interests not included in equity (note 19)	—	—	—	—	—	—	4,952	4,952
Other comprehensive income	—	—	—	—	—	(31,810)	(6,826)	(38,636)
Dividends declared and distributions to non-controlling interests	—	—	—	—	(125,696)	—	(3,926)	(129,622)
Dividends and issuance of shares under dividend reinvestment plan	33,862	—	—	—	(33,862)	—	—	—
Common shares issued upon conversion of subscription receipts	110,503	—	(110,503)	—	—	—	—	—
Common shares issued pursuant to share-based awards (note 15(c))	18,944	—	—	(5,505)	(4,274)	—	—	9,165
Share-based compensation	—	—	—	5,916	—	—	—	5,916
Contributions received from non-controlling interests	—	—	—	—	—	—	12,752	12,752
Non-controlling interest of acquired operating entity	—	—	—	—	—	—	237,156	237,156
Balance, December 31, 2016	$ 1,972,203	$ 213,805	$ —	$ 38,652	$ (556,024)	$ 254,927	$ 562,358	$ 2,485,921

See accompanying notes to consolidated financial statements

Algonquin Power & Utilities Corp.
Consolidated Statements of Cash Flows

(thousands of Canadian dollars)	Year ended December 31 2017	2016
Cash provided by (used in):		
Operating Activities		
Net earnings from continuing operations	$ 130,846	$ 92,374
Adjustments and items not affecting cash:		
Depreciation and amortization	329,273	195,751
Deferred taxes	85,286	28,675
Unrealized loss (gain) on derivative financial instruments	1,764	(18,689)
Share-based compensation expense	10,630	5,916
Cost of equity funds used for construction purposes	(3,014)	(2,774)
Pension and post-employment contributions in excess of expense	(26,893)	(13,491)
Non-cash revenue and other income	—	(10,467)
Distributions received from equity investments, net of income	3,141	653
Write-down of long-lived assets	789	6,259
Changes in non-cash operating items (note 24)	(74,026)	3,704
	457,796	287,911
Financing Activities		
Increase in long-term debt	1,838,035	2,399,009
Decrease in long-term debt	(3,131,717)	(68,423)
Issuance of convertible debentures, net of costs	743,881	357,694
Cash dividends on common shares	(170,199)	(118,145)
Dividends on preferred shares	(10,400)	(10,400)
Contributions from non-controlling interests	333,395	13,468
Production-based cash contributions from non-controlling interest	10,622	9,454
Distributions to non-controlling interests	(4,135)	(4,307)
Issuance of common shares, net of costs	556,634	1,526
Proceeds from settlement of derivative assets	48,381	—
Proceeds from exercise of share options	12,761	18,461
Shares surrendered to fund withholding taxes on exercised share options	(4,401)	(5,218)
Increase in other long-term liabilities	33,030	6,486
Decrease in other long-term liabilities	(8,751)	(4,269)
	247,136	2,595,336
Investing Activities		
Decrease (increase) in restricted cash	2,011,204	(2,007,732)
Acquisitions of operating entities	(2,047,401)	(432,699)
Divestiture of operating entity	111,043	—
Additions to property, plant and equipment	(740,023)	(405,743)
Increase in other assets	(9,122)	(20,501)
Receipt of principal on notes receivable	—	319,160
Increase in long-term investments	(82,449)	(347,901)
	(756,748)	(2,895,416)
Effect of exchange rate differences on cash	(4,051)	(2,231)
Decrease in cash and cash equivalents	(55,867)	(14,400)
Cash and cash equivalents, beginning of year	110,417	124,817
Cash and cash equivalents, end of year	$ 54,550	$ 110,417

Supplemental disclosure of cash flow information:	2017	2016
Cash paid during the year for interest expense	$ 198,045	$ 131,783
Cash paid during the year for income taxes	$ 11,377	$ 13,369
Non-cash financing and investing activities:		
Property, plant and equipment acquisitions in accruals	$ 141,708	$ 146,301
Issuance of common shares under dividend reinvestment plan and share-based compensation plans	$ 51,178	$ 35,409
Issuance of common shares upon conversion of convertible debentures	$ 1,102,304	$ —
Issuance of common shares upon conversion of subscription receipts	$ —	$ 110,503
Acquisition of equity investments in exchange for loan receivable and payable	$ 2,353	$ 26,035

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 North American business units consisting of the Liberty Power Group and the Liberty Utilities Group. The Liberty Power Group ("Liberty Power Group") owns and operates a diversified portfolio of non-regulated renewable and thermal electric generation utility assets; the Liberty Utilities Group ("Liberty Utilities Group") owns and operates a portfolio of regulated electric, natural gas, water distribution and wastewater collection utility systems and transmission operations.

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(r)).

(c) Business combinations, intangible assets and goodwill

The Company accounts for acquisitions of entities or assets which meet the definition of a business as business combinations. The determination of whether the definition of a business has been met for a development stage project depends on the stage of development (permitting, customer contracting, financing, construction) and the significance of the development risk with respect to achieving commercial operation. Business combinations are accounted for using the acquisition method. Assets acquired and liabilities assumed are measured at their fair value at the acquisition date. 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 acquisitions 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 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 regulated utility operating companies owned by the Company are subject to rate regulation generally overseen by the public utility commission of the states in which they operate (the "Regulator"). The Regulator provides the final determination of the rates charged to customers. APUC's regulated utility operating companies are accounted for under the principles of U.S. Financial Accounting Standards Board ("FASB") ASC Topic 980, Regulated Operations ("ASC 980"). 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.

1. Significant accounting policies (continued)

(d) Accounting for rate regulated operations (continued)

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 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.

(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 and requirements of ISO New England, Inc. As of December 31, 2016, restricted cash also included cash of U.S. $1,495,774 transfered to a paying agent for purposes of distribution to holders of common shares of The Empire District Electric Company and its subsidiaries ("Empire") on January 1, 2017 (note 3(a)). 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(d)) 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.

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, together 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 asset 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 capital leases are initially recorded at cost determined as the present value of minimum lease payments.

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, dividend, equity and other income on the consolidated statements of operations.

	2017	2016
Interest capitalized on non-regulated property	**$ 5,558**	$ 3,259
AFUDC capitalized on regulated property:		
Allowance for borrowed funds	**1,673**	1,167
Allowance for equity funds	**3,014**	2,774
Total	**$ 10,245**	$ 7,200

Improvements that increase or prolong the service life or capacity of an asset are capitalized. Cost 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.

Investment tax credits and government 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. 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 13(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. Investment tax credits and government grants related to operating expenses such as maintenance and repairs costs are recorded as a reduction of the related expense.

1. Significant accounting policies (continued)

(j) Property, plant and equipment (continued)

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	
	2017	2016	2017	2016
Generation	**3 - 60**	3 - 60	**33**	32
Distribution	**5 - 100**	5 - 100	**40**	41
Equipment	**5 - 50**	5 - 50	**13**	11

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.

In accordance with regulator-approved accounting policies, when depreciable property, plant and equipment of the Liberty Utilities 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 Company 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 are recognized in operating, maintenance and fuel expenditures excluding depreciation expense.

As at December 31, 2017, the Company's consolidated balance sheet includes $833,578 of cost of plant in service of and $225,156 of accumulated depreciation related to commonly owned facilities. Total expenditures for the year ended December 31, 2017 were $99,930.

(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 analysis 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 of 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).

1. Significant accounting policies (continued)

(m) Variable interest entities (continued)

The Company has equity and notes receivable interests in two power generating facilities. APUC has determined that both entities are considered a VIE 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 $84,550 (2016 - $87,189) and $35,914 (2016 - $40,398), respectively. The portion of long-term debt which has recourse to the Company is $3,900 (2016 - $6,900). The financial performance of these facilities reflected on the consolidated statements of operations includes non-regulated energy sales of $22,743 (2016 - $29,132), operating expenses and amortization of $5,564 (2016 - $6,175) and interest expense of $3,573 (2016 - $4,064).

(n) Long-term investments and notes receivable

Investments in which APUC has significant influence but not control are accounted using the equity method. 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 investees in interest, dividend, equity and other income in the consolidated statements of operations.

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 acquired 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 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"), 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. The costs of the Company's pension for employees are expensed over the periods during which employees render service and are recognized as part of administrative expenses in the consolidated statements of operations.

1. Significant accounting policies (continued)

(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, or regulatory assets when the amount is recoverable through rates. 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, or regulatory assets when the amount is recoverable through rates. Actual expenditures incurred are charged against the obligation.

(q) 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; 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 expense 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.

(r) 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.

Certain of the Company's U.S. based wind and solar businesses are organized as limited liability corporations ("LLC") and partnerships and have non-controlling Class A membership equity investors ("Class A partnership units" or "Class A Equity Investors") which are entitled to allocations of earnings, tax attributes and cash flows in accordance with contractual agreements. These LLC and partnership's agreements have liquidation rights and priorities that are different from the underlying percentages ownership interests. In those situations, simply applying the percentage ownership interest to 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 19).

The HLBV method uses a balance sheet approach. A calculation is prepared at each balance sheet date to determine the amount that Class A 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 Class A 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 Class A Equity Investors report net income. The calculation varies in its complexity depending on the capital structure and the tax considerations of the investments.

1. Significant accounting policies (continued)

(r) Non-controlling interests (continued)

Equity instruments subject to redemption upon the occurrence of uncertain events not solely within APUC's control are classified as temporary equity 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.

(s) Recognition of revenue

Revenue derived from non-regulated energy generation sales, which are mostly under long-term power purchase contracts, is recorded at the time electrical energy is delivered.

Qualifying renewable energy projects receive renewable energy credits ("REC") 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 REC and SREC can be traded and the owner of the REC or SREC can claim to have purchased renewable energy. RECs and SRECs are primarily sold under fixed contracts, and revenue for these contracts is recognized at the time of generation. Any REC's or SRECs generated above contracted amounts are held in inventory, with the offset recorded as a decrease in operating expenses.

Revenue related to utility electricity and natural gas sales and distribution are recorded when the electricity or natural gas 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.

Revenue for certain of the Company's regulated utilities is subject to revenue decoupling mechanisms approved by their respective regulators which require to charge 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 (note 7(e)).

Water reclamation and distribution revenues are recorded 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 is 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.

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 rates 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 is recorded net of sales taxes.

1. Significant accounting policies (continued)

(t) Foreign currency translation

APUC's reporting currency is the Canadian dollar.

The Company's U.S. operations are determined to have the U.S. dollar as their functional currency since the preponderance of operating, financing and investing transactions are denominated in U.S. dollars. The financial statements of these operations are translated into Canadian 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.

(u) 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 20). Investment tax credits for our rate regulated operations are deferred and amortized as a reduction to income tax expense over the estimated useful lives of the properties. Other income tax credits are treated as a reduction to income tax expense in the year the credit arises or future periods to the extent that realization of such benefit is more likely than not.

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.

(v) 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.

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 exposure, interest risk and price risk exposure associated with sales of generated electricity.

1. Significant accounting policies (continued)

(v) Financial instruments and derivatives (continued)

For derivatives designated in a cash flow hedge relationship, the effective portion of the change in fair value is recognized in OCI. The ineffective portion is immediately recognized in earnings. 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. To the extent that the hedge is ineffective, such differences are recognized in earnings.

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.

(w) 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.

(x) 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.

(y) 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 measurement of deferred taxes and 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 ASU 2016-17 Consolidation (Topic 810): Interests Held through Related Parties That Are under Common Control. This update amends the consolidation guidance on how a reporting entity that is the single decision maker of a VIE should treat indirect interests in the entity held through related parties that are under common control with the reporting entity when determining whether it is the primary beneficiary of that VIE. The adoption of this update in the first quarter of 2017 had no impact on the Company's consolidated financial statements.

The FASB issued ASU 2016-09, Compensation - Stock Compensation (Topic 718), to simplify several aspects of the accounting for share-based payment transactions, including the income tax consequences, classification of awards as either equity or liabilities, and classification on the statement of cash flows. The adoption of this update in the first quarter of 2017 had no material impact on the Company's consolidated financial statements. The Company continues to record the stock-based compensation expense adjusted for estimated forfeitures.

The FASB issued ASU 2016-06, Derivatives and Hedging (Topic 815): Contingent Put and Call Options in Debt Instruments, to clarify the requirements for assessing whether contingent call (put) options that can accelerate the payment of principal on debt instruments are clearly and closely related to their debt hosts, which is one of the criteria for bifurcating an embedded derivative. An entity performing the assessment under the amendments in this Update is required to assess the embedded call (put) options solely in accordance with the four-step decision sequence. The adoption of this update in the first quarter of 2017 had no impact on the Company's consolidated financial statements.

The FASB issued ASU 2016-05, Derivatives and Hedging (Topic 815): Effect of Derivative Contract Novations on Existing Hedge Accounting Relationships, to clarify that a change in the counterparty to a derivative instrument that has been designated as the hedging instrument does not, in and of itself, require dedesignation of that hedging relationship provided that all other hedge accounting criteria continue to be met. The adoption of this update in the first quarter of 2017 had no impact on the Company's consolidated financial statements.

The FASB issued ASU 2015-11, Inventory (Topic 330): Simplifying the Measurement of Inventory, to simplify the subsequent measurement of inventory by replacing the current lower of cost and market test with a lower of cost and net realizable value test. The adoption of this update in the first quarter of 2017 had no impact on the Company's consolidated financial statements.

(b) Recently issued accounting guidance not yet adopted

The FASB issued ASU 2018-02, Income Statement - Reporting Comprehensive Income (Topic 220): Reclassification of Certain Tax Effects from Accumulated Other Comprehensive Income to allow a reclassification from accumulated other comprehensive income to retained earnings for stranded tax effects resulting from the Tax Cuts and Jobs Act. The update is effective for fiscal years beginning after December 15, 2018, and interim periods within those fiscal years . Early application is permitted in any interim period after issuance of the update. The Company is currently assessing the impacts of this update.

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 update is effective for fiscal years beginning after December 15, 2018, and interim periods within those fiscal years. Early application is permitted in any interim period after issuance of the update. The Company is currently assessing the impacts of this update. The Company expects to early adopt this update on January 1, 2018.

The FASB issued ASU 2017-09, Compensation-Stock Compensation (Topic 718): Scope of Modification Accounting, to provide clarity and reduce both diversity in practice and cost and complexity when applying the guidance in Topic 718, Compensation-Stock Compensation, to a change to the terms or conditions of a share-based payment award. The Company applies the guidance in this update for modifications subsequent to December 15, 2017.

2. Recently issued accounting pronouncements (continued)

(b) Recently issued accounting guidance not yet adopted (continued)

The FASB issued ASU 2017-07 Compensation—Retirement Benefits (Topic 715): Improving the Presentation of Net Periodic Pension Cost and Net Periodic Post-retirement Benefit Cost, to improve the reporting of defined benefit pension cost and post-retirement benefit cost ("net benefit cost") in the financial statements. This update requires the service cost component to be reported in the same line item or items as other compensation costs arising from services rendered by the pertinent employees during the period. The other components of net benefit cost are required to be presented in the income statement separately from the service cost component and outside a subtotal of income from operations. The update will also only allow the service cost component to be eligible for capitalization when applicable. The Company will adopt this guidance effective January 1, 2018. Following the effective date of this ASU, the Company expects its regulated operations to only capitalize the service costs component and therefore no regulatory to U.S. GAAP reporting differences are anticipated. The Company intends to apply the practical expedient for retrospective application on the statement of operations.

The FASB issued ASU 2017-05 Other Income—Gains and Losses from the Derecognition of Nonfinancial Assets (Subtopic 610-20): Clarifying the Scope of Asset Derecognition Guidance and Accounting for Partial Sales of Nonfinancial Assets. The update clarifies the scope of the standard as well as provides additional guidance on partial sales of nonfinancial assets. The update is effective for fiscal years and interim periods beginning after December 15, 2017. Early adoption is permitted however the update must be adopted at the same time as ASU 2014-09. No impact on the consolidated financial statements is expected from 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 FASB issued ASU 2017-01 Business Combinations (Topic 805): Clarifying the Definition of a Business. The update is intended to clarify the definition of a business with the objective of adding guidance to assist entities with evaluating whether transactions should be accounted for as acquisitions (or disposals) of assets or businesses. The standard is effective for fiscal years and interim periods beginning after December 15, 2017. The amendments in the Update should be applied prospectively. The Company will follow the pronouncements of this Update after the effective date.

The FASB issued ASU 2016-18 Statement of Cash Flows (Topic 230): Restricted Cash to eliminate current diversity in practice in the classification and presentation of changes in restricted cash on the statement of cash flows. The standard is effective for fiscal years and interim periods beginning after December 15, 2017. The Company currently present changes in restricted cash as investing activities. The adoption of this standard will change the presentation of restricted cash on the consolidated statement of cash flows.

The FASB issued ASU 2016-16, Income Taxes (Topic 740): Intra-Entity Transfers of Assets Other Than Inventory. The new standard requires the recognition of current and deferred income taxes for an intra-entity transfer of an asset other than inventory. Current GAAP prohibits the recognition of current and deferred income taxes on these transactions until the asset has been sold to an outside party. The standard is effective for fiscal years and interim periods beginning after December 15, 2017. Early adoption is permitted. No impact on the consolidated financial statements is expected from the adoption of this Update.

The FASB issued ASU 2016-15 Statement of Cash Flows (Topic 230) Classification of Certain Cash Receipts and Cash Payments in order to eliminate current diversity in practice in how certain cash receipts and cash payments are presented and classified in the statement of cash flows. The standard is effective for fiscal years and interim periods beginning after December 15, 2017. Early adoption is permitted. No impact on the consolidated financial statements is expected from the adoption of this Update.

2. Recently issued accounting pronouncements (continued)

(b) Recently issued accounting guidance not yet adopted (continued)

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 GAAP with a methodology that reflects expected credit losses. The standard is effective for fiscal years and interim periods beginning after December 15, 2019. Early adoption for fiscal years and interim periods beginning after December 15, 2018 is permitted. The Company is currently in the process of evaluating 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.

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 issued an amendment to ASC Topic 842 which permits companies to elect an optional transition practical expedient to not evaluate existing land easements under the new standard if the land easements were not previously accounted for under existing lease guidance. The FASB also voted to amend ASC Topic 842 to allow companies to elect not to restate their comparative periods in the period of adoption when transitioning to the standard. The standard is effective for fiscal years and interim periods beginning after December 15, 2018. Early adoption is permitted.

The Company is in the process of evaluating the impact of adoption of this standard on its financial statements and disclosures. The Company held training sessions with the finance team and is currently in the process of creating an inventory of its lease contracts and analyzing the terms and conditions under the requirements of this new standard. The Company continues to monitor FASB amendments to ASC Topic 842.

The FASB issued ASU 2016-01, Financial Instruments - Overall (Subtopic 825-10): Recognition and Measurement of Financial Assets and Financial Liabilities to simplify the measurement, presentation, and disclosure of financial instruments. The standard is effective for fiscal years and interim periods beginning after December 15, 2017. Early adoption is permitted. The presentation of unrealized gains/ losses from the Company's available-for-sale investments will change on the consolidated statement of comprehensive income. Certain disclosures with regards to financial liabilities will change based on the updated requirements.

The FASB issued a revenue recognition standard codified as ASC 606, Revenue from Contracts with Customers. This issued accounting standard provides accounting guidance for all revenue arising from contracts with customers and affects all entities that enter into contracts to provide goods or services to their customers unless the contracts are in the scope of other U.S. GAAP requirements, such as the leasing literature. The core principal of the accounting guidance is that an entity should recognize revenue when it transfers promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. ASC 606 is expected to require significantly expanded disclosures regarding the qualitative and quantitative information of the Company's nature, amount, timing, and uncertainty of revenue and cash flows arising from contracts with customers. This new revenue standard is required to be applied for fiscal years and interim periods beginning after December 15, 2017 using either a full retrospective approach for all periods presented in the period of adoption or a modified retrospective approach. The Company has not elected to early adopt.

The Company has completed its impact assessment. At this point, the Company expects the adoption of Topic 606 will have an immaterial impact on the consolidated financial statements and the pattern of revenue recognition. The Company also evaluated the disclosure requirements and determined that the disaggregation of revenue information required by the new standard will not have a significant impact on the Company’s information gathering processes and procedures as the revenue information required by the standard is consistent with historical revenue information gathered by the Company for financial reporting purposes. The Company intends to adopt the new revenue recognition standard using the modified retrospective method.

3. Business acquisitions and development projects

(a) Acquisition of Empire

On January 1, 2017, the Company completed the acquisition of Empire, a Joplin, Missouri based regulated electric, gas and water utility, serving customers in Missouri, Kansas, Oklahoma and Arkansas.

The purchase price of approximately U.S. $2,414,000 for the acquisition of Empire consists of cash payment to Empire shareholders of U.S. $34.00 per common share and the assumption of approximately U.S. $855,000 of debt. The cash payment was funded with the acquisition facility for an amount of U.S. $1,336,440 (note 9(b)), proceeds received from the initial instalment of convertible debentures (note 14) and existing credit facility. The costs related to the acquisition have been expensed through the consolidated statements of operations.

The following table summarizes the final allocation of the purchase consideration to the assets and liabilities acquired as at January 1, 2017 based on their fair values, using the exchange rate on that date of U.S. $1.00 = CAD $1.3427.

Working capital	$	55,441
Property, plant and equipment		2,764,441
Goodwill		1,010,273
Regulatory assets		318,130
Other assets		58,553
Long-term debt		(1,218,563)
Regulatory liabilities		(195,489)
Pension and other post-employment benefits		(105,005)
Deferred income tax liability, net		(562,397)
Other liabilities		(102,759)
Total net assets acquired	$	2,022,625
Cash and cash equivalent	$	2,338
Total net assets acquired, net of cash and cash equivalent	$	2,020,287

The determination of the fair value of assets acquired and liabilities assumed is based upon management's estimates and certain assumptions.

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. Goodwill is reported under the Liberty Utilities Group segment.

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 the Empire's assets is 39 years.

The table below presents the consolidated pro forma revenue and net income for the year ended December 31, 2017 and 2016, assuming the acquisition of Empire had occurred on January 1, 2016. Pro forma net income includes the impact of fair value adjustments incorporated in the preliminary purchase price allocation above and adjustments necessary to reflect the financing costs as if the acquisition had been financed on January 1, 2016. However, non-recurring acquisition-related expenses are excluded from net income.

	Year Ended December 31	
	2017	**2016**
Revenues	**$ 1,977,809**	$ 1,908,340
Net earnings attributable to common shareholders	**$ 229,976**	$ 213,983

3. Business acquisitions and development projects (continued)

(a) Acquisition of Empire (continued)

This pro forma information does not purport to represent what the actual results of operations of the Company would have been had the acquisition occurred on this date nor does it purport to predict the results of operations for future periods.

(b) Investment in joint venture with Abengoa and investment in Atlantica

On November 1, 2017, APUC entered into an agreement to create a joint venture ("AAGES") with Seville, Spain-based Abengoa, S.A ("Abengoa") to identify, develop, and construct clean energy and water infrastructure assets with a global focus. Concurrently with the creation of the AAGES joint venture, APUC entered into a definitive agreement to purchase from Abengoa a 25% equity interest in Atlantica Yield plc ("Atlantica") for a total purchase price of approximately U.S. $608,000, based on a price of U.S. $24.25 per ordinary share of Atlantica plus a contingent payment of up to U.S. $0.60 per-share payable two years after closing, subject to certain conditions. The transaction is expected to close in the first quarter of 2018, subject to regulatory approvals and other closing conditions.

(c) Great Bay Solar Project

On August 12, 2015, the Company acquired rights to develop a 75 MWac solar project in Somerset County, Maryland. The project consists of four separate sites: as of December 31, 2017, two sites had been fully synchronized with the power grid, one site partially placed in service, with the remaining portion of the facility expected to be placed in service in Q1 2018.

The Great Bay Solar Facility is controlled by a subsidiary of APUC (Great Bay Holdings, LLC). Approximately U.S. $59,000 of the permanent project financing will come from tax equity investors. Equity capital contribution of U.S. $42,750 was received in 2017 with the remaining expected to be received in early 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.

(d) Acquisition of the St. Lawrence Gas Company, Inc.

On August 31, 2017, the Company entered into a definitive agreement to acquire St. Lawrence Gas Company, Inc. ("SLG"). SLG is a rate-regulated natural gas distribution utility serving customers in northern New York state. The total purchase price for the transaction is U.S. $70,000, less total third-party debt of SLG outstanding at closing, and subject to customary working capital adjustments. Closing of the transaction remains subject to regulatory approval and other closing conditions and is expected to occur in late 2018 or early 2019.

(e) Approval to acquire the Perris Water Distribution System

On August 10, 2017 the Company's board approved the acquisition of two water distribution systems serving customers from the City of Perris, California. The anticipated purchase price of U.S. $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. Liberty Utilities expects to file the advice letter to acquire the water utility with the California Public Utility Commission in Q1 2018 with approval expected in late 2018.

(f) Luning Solar Facility

Luning Utilities (Luning Holdings) LLC (the "Luning Holdings") is owned by the Calpeco Electric System. The 50MWac solar generating facility is located in Mineral County, Nevada. During 2016, a tax equity agreement was executed. The Class A partnership units are owned by a third-party tax equity investor who funded U.S. $7,826 as of December 31, 2016 and U.S. $31,212 on February 17, 2017. With its interest, the tax equity investor will receive the majority of the tax attributes associated with the Luning Solar project. During a six-month period in year 2022, the tax investor has the right to withdraw from Luning Holdings and require the Company to redeem its remaining interests for cash. As a result, the Company accounts for this interest as "Redeemable non-controlling interest" outside of permanent equity on the consolidated balance sheets (note 19). Redemption is not considered probable as of December 31, 2017.

On February 15, 2017, as the Luning Solar Facility achieved commercial operation, Luning Holdings obtained control for a total purchase price of U.S. $110,856.

3. Business acquisitions and development projects (continued)

(f) Luning Solar Facility (continued)

The following table summarizes the allocation of the assets acquired and liabilities assumed at the acquisition date:

Working capital	$	198
Property, plant and equipment		145,045
Asset retirement obligation		(714)
Non-controlling interest (tax equity)		(50,548)
Total net assets acquired	$	93,981

The determination of the fair value of assets acquired and liabilities assumed is based upon management's estimates and certain assumptions.

(g) Bakersfield II Solar Facility

On December 14, 2016, the Company completed construction and placed in service a 10 MWac solar powered generating facility located adjacent to the Company's 20 MWac Bakersfield I Solar Facility in Kern County, California ("Bakersfield II Solar Facility"). Commercial operations as defined by the power purchase agreement was reached on January 11, 2017.

The Bakersfield II Solar Facility is controlled by a subsidiary of APUC (the "Bakersfield II Partnership"). The Class A partnership units are owned by a third-party tax equity investor who funded U.S. $2,454 on November 29, 2016 and approximately U.S. $9,800 on February 28, 2017. With 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.

(h) Wind Turbine Components Purchase

In 2016, the Company purchased approximately $75,000 of wind turbine components that will qualify between 500 MW and 700 MW of new wind powered projects for the full U.S. $0.023/kWh renewable energy production tax credit under the safe harbor guidelines established by the U.S. Internal Revenue Service, provided that such projects are placed in service before the end of 2020.

(i) Acquisition of Park Water System

On January 8, 2016, the Company completed the acquisition of Western Water Holdings, LLC which is the parent company of Park Water Company ("Park Water System"), a regulated water distribution utility. The total purchase price for the Park Water System is $353,077 (U.S. $249,540), net of the debt assumed of U.S. $91,750 and is subject to certain closing adjustments. All costs related to the acquisition have been expensed in the consolidated statements of operations. At the time of acquisition, Park Water System owned and operated three regulated water utilities engaged in the production, treatment, storage, distribution, and sale of water in southern California and western Montana. Those three utilities were named Park Water Company, Apple Valley Ranchos Water Co. and Mountain Water Company.

Mountain Water was the subject of a condemnation lawsuit filed by the city of Missoula. On June 22, 2017, the city of Missoula took possession of Mountain Water's assets (note 23(a)).

3. Business acquisitions and development projects (continued)

(i) Acquisition of Park Water System (continued)

The following table summarizes the allocation of the assets acquired and liabilities assumed at the acquisition date:

Working capital	$	2,045
Property, plant and equipment		345,254
Notes receivable		1,781
Goodwill		210,463
Regulatory assets		54,548
Other assets		185
Long-term debt		(146,727)
Regulatory liabilities		(3,758)
Pension and OPEB		(18,747)
Deferred income tax liability, net		(51,795)
Other liabilities		(40,172)
Total net assets acquired	$	353,077

The determination of the fair value of assets acquired and liabilities assumed is based upon management's estimates and certain assumptions. Immaterial changes to the initial allocation were recorded during 2016.

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. Goodwill is reported under the Liberty Utilities Group segment.

Property, plant and equipment 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 the Park Water System assets is 40 years.

The Park Water System contributed revenue of $91,817 (2016 - $96,695) and pre-tax net earnings of $17,620 (2016 - $25,374) to the Company's consolidated financial results for the year ended December 31, 2017.

4. Accounts receivable

Accounts receivable as of December 31, 2017 include unbilled revenue of $98,214 (2016 - $57,822) from the Company's regulated utilities. Accounts receivable as of December 31, 2017 are presented net of allowance for doubtful accounts of $6,968 (2016 - $7,064).

5. Property, plant and equipment

Property, plant and equipment consist of the following:

2017	Cost	Accumulated depreciation	Net book value
Generation	$ 2,988,569	$ 494,912	$ 2,493,657
Distribution	5,247,499	483,345	4,764,154
Land	89,935	—	89,935
Equipment and other	143,158	51,026	92,132
Construction in progress			
Generation	263,418	—	263,418
Distribution	206,197	—	206,197
	$ 8,938,776	$ 1,029,283	$ 7,909,493

2016	Cost	Accumulated depreciation	Net book value
Generation	$ 2,613,267	$ 419,227	$ 2,194,040
Distribution	2,638,488	462,454	2,176,034
Land	60,868	—	60,868
Equipment and other	139,961	44,700	95,261
Construction in progress			
Generation	197,405	—	197,405
Distribution	166,338	—	166,338
	$ 5,816,327	$ 926,381	$ 4,889,946

Generation assets include cost of $142,789 (2016 - $142,246) and accumulated depreciation of $43,792 (2016 - $39,958) related to facilities under capital lease or owned by consolidated VIEs. Depreciation expense of facilities under capital lease was $2,117 (2016 - $2,117).

Distribution assets include cost of $2,234,243 and accumulated depreciation of $587,202 related to regulated generation and transmission assets. Water and wastewater distribution assets include expansion costs of $1,000 on which the Company does not currently earn a return.

For the year ended December 31, 2017, contributions received in aid of construction of $16,044 (2016 - $49,794) have been credited to the cost of the assets. The 2016 credit also includes Canadian renewable and conservation expense refundable tax credit for the St Damase wind facility in the amount of $14,086.

6. Intangible assets and goodwill

Intangible assets consist of the following:

2017	Cost	Accumulated amortization	Net book value
Power sales contracts	$ 70,929	$ 46,263	$ 24,666
Customer relationships	33,619	11,085	22,534
Interconnection agreements	17,790	882	16,908
	$ 122,338	$ 58,230	$ 64,108

6. Intangible assets and goodwill (continued)

	2016		
	Cost	Accumulated amortization	Net book value
Power sales contracts	$ 72,207	$ 44,641	$ 27,566
Customer relationships	35,979	10,999	24,980
Interconnection agreements	13,000	557	12,443
	$ 121,186	$ 56,197	$ 64,989

Estimated amortization expense for intangible assets for the next year is $3,540, $3,390 in year two, $3,380 in year three, $3,040 in year four and $2,720 in year five.

All goodwill pertains to the Liberty Utilities Group. Changes in goodwill are as follows:

Balance, January 1, 2016	$ 110,493
Business acquisitions	210,463
Foreign exchange	(14,315)
Balance, December 31, 2016	$ 306,641
Business acquisitions (note 3(a))	1,010,273
Divestiture of operating entity (note 23(a))	(35,107)
Foreign exchange	(85,573)
Balance, December 31, 2017	$ 1,196,234

7. Regulatory matters

The Company's regulated utility operating companies are 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 policies, issuance of securities, acquisitions and other matters. These utilities operate under cost-of-service regulation as administered by these state 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.

On January 1, 2017, the Company completed the acquisition of Empire, an operating public utility engaged in the generation, purchase, transmission, distribution and sale of electricity in parts of Missouri, Kansas, Oklahoma and Arkansas. Empire also provides regulated water utility distribution services to three towns in Missouri. The Empire District Gas Company, a wholly owned subsidiary, is engaged in the distribution of natural gas in Missouri. These businesses are subject to regulation by the Missouri Public Service Commission, the State Corporation Commission of the State of Kansas, the Corporation Commission of Oklahoma, the Arkansas Public Service Commission and the Federal Energy Regulatory 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.

7. Regulatory matters (continued)

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 U.S. $'000	Effective Date
EnergyNorth Gas System	New Hampshire	GRC	$6,750	Temporary increase effective July 1, 2017
Granite State Electric System	New Hampshire	General Rate Case ("GRC")	$6,105	July 1, 2016
Calpeco Electric System	California	Post-Test Year Adjustment Mechanism	$2,175	January 1, 2018
New England Gas System	Massachusetts	GRC	$8,300	U.S. $7,800 effective March 1, 2016 U.S. $500 effective March 1, 2017
New England Gas System	Massachusetts	Gas System Enhancement Plan	$2,928	May 1, 2017
Midstates Gas System	Illinois	GRC	$2,200	June 7, 2017
Peach State Gas System	Georgia	GRAM	$2,725	March 1, 2016
Bella Vista Water System Rio Rico Water/Sewer System	Arizona	GRC	$1,935	November 1, 2016
CalPeco Electric System	California	GRC	$8,318	January 1, 2016
Various			$3,551	2016, 2017 & 2018

7. Regulatory matters (continued)

Regulatory assets and liabilities consist of the following:

	2017	2016
Regulatory assets		
Environmental remediation (a)	**$ 103,761**	$ 104,160
Pension and post-employment benefits (b)	**132,615**	75,527
Debt premium (c)	**72,016**	25,173
Fuel and commodity costs adjustment (d)	**43,311**	6,990
Rate adjustment mechanism (e)	**44,523**	40,602
Clean Energy and other customer programs (f)	**25,820**	2,106
Deferred construction costs (g)	**17,994**	—
Asset retirement (h)	**20,172**	2,113
Income taxes (i)	**45,847**	10,182
Rate case costs (j)	**11,660**	8,572
Other	**33,415**	16,539
Total regulatory assets	**$ 551,134**	$ 291,964
Less current regulatory assets	**(83,508)**	(48,440)
Non-current regulatory assets	**$ 467,626**	$ 243,524
Regulatory liabilities		
Income taxes (i)	**$ 402,868**	$ 1,501
Cost of removal (k)	**231,064**	110,330
Rate-base offset (l)	**16,577**	20,946
Fuel and commodity costs adjustment (d)	**29,535**	34,012
Deferred compensation received in relation to lost production (m)	**11,789**	—
Deferred construction costs - fuel related (g)	**9,306**	—
Pension and post-employment benefits (b)	**12,648**	5,481
Other	**11,269**	10,464
Total regulatory liabilities	**$ 725,056**	$ 182,734
Less current regulatory liabilities	**(47,278)**	(47,769)
Non-current regulatory liabilities	**$ 677,778**	$ 134,965

(a) Environmental remediation

Actual expenditures incurred for the clean-up of certain former gas manufacturing facilities (note 13(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. An amount of U.S. $21,626 relates to an acquisition and was authorized for recognition as an asset by the regulator. Recovery is anticipated to be approved in a final rate order to be received on completion of the next general rate case. 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 pension and post-employments benefits liability is related to tracking accounts pertaining primarily to Park Water Company. The amounts recorded in these accounts occur when actual expenses have been less than adopted and refunds are expected to occur in future periods.

7. Regulatory matters (continued)

(c) Debt premium

Debt premium on acquired debt is recovered as a component of the weighted average cost of debt.

(d) Fuel and commodity costs adjustment

The revenue from the utilities includes a component which 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 not recorded on the consolidated statements of operations but rather 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 25(b)(i)) are recoverable through the commodity costs adjustment.

(e) Rate adjustment mechanism

Revenue for Calpeco Electric System, Park Water System, Peach State Gas System and New England Gas Systems are subject to a revenue decoupling mechanism approved by their respective regulator which require 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.

(f) 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.

(g) Deferred construction costs

Deferred construction costs reflects deferred construction costs and fuel related costs of specific generating facilities of Empire. These amounts are being recovered over the life of the plants.

(h) Asset retirement

The costs of retirement of assets are expected to be recovered through rates as well as the on-going liability accretion and asset depreciation expense.

(i) 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.

The Tax Cuts and Jobs Act ("the Act") was enacted on December 22, 2017. Among other provisions, the Act reduces the corporate income tax rate from 35% to 21%. A reduction of regulatory asset and an increase to regulatory liability was recorded for excess deferred taxes probable of being refunded to customers of $411,409.

(j) Rate case costs

The costs to file, prosecute and defend rate case applications are referred to as rate case costs. These costs are capitalized and amortized over the period of rate recovery granted by the regulator.

(k) Cost of removal

The regulatory liability for cost of removal represents amounts that have been collected from ratepayers for costs that are expected to be incurred in the future to retire the utility plant.

(l) 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.

7. Regulatory matters (continued)

(m) Deferred compensation received in relation to lost production

The regulatory liability for deferred compensation received from lost production represents Empire's refund from Southwest Power Administration for lost revenues at one of its generating facilities. These costs are being amortized over the period approved by state regulators.

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 case costs.

8. Long-term investments

Long-term investments consist of the following:

	2017	2016
Equity-method investees		
Red Lily I Wind Facility (a)	**$ 22,799**	$ 23,504
Deerfield Wind Project (b)	**—**	34,727
Amherst Island Wind Project (c)	**11,191**	558
Other	**6,489**	5,630
	$ 40,479	$ 64,419
Notes receivable		
Development loans (d)	**$ 37,710**	$ 32,125
Other	**4,163**	6,058
	41,873	38,183
Available-for-sale investment	**—**	169
Other investments	**2,115**	2,662
Total long-term investments	**$ 84,467**	$ 105,433

(a) Red Lily I Wind Facility

Up to April 12, 2016, the Red Lily I Partnership (the “Partnership”) was 100% owned by an independent investor. APUC provided operation and supervision services to the Red Lily I project ("Red Lily I Wind Facility"), a 26.4 MW wind energy facility located in southeastern Saskatchewan. The Company’s investment in the Red Lily I Wind Facility up to that date was in the form of subordinated debt facilities of the Partnership.

Effective April 12, 2016, the Company exercised its option to subscribe for a 75% equity interest in the Partnership in exchange for the outstanding amount on its subordinated loans. The amount by which the carrying value of the Company's investment exceeds the Company's proportionate share of the Partnership's net assets is not material.

Due to certain participating rights being held by the minority investor, the decisions which most significantly impact the economic performance of Red Lily I require unanimous consent. As such, APUC is deemed, under U.S. GAAP, to not have control over the Partnership. As APUC exercises significant influence over operating and financial policies of Red Lily I, the Company accounts for the Partnership using the equity method. The Red Lily I Wind Facility contributed equity income of $2,776 (2016 - $1,288) to the Company's consolidated financial results for the year ended December 31, 2017.

8. Long-term investments (continued)

(b) Deerfield Wind Project

On October 19, 2015, the Company acquired a 50% equity interest in Deerfield Wind SponsorCo LLC ("Deerfield SponsorCo"), which indirectly owns a 150 MW construction-stage wind development project ("Deerfield Wind Project") in the state of Michigan. On March 14, 2017, the Company acquired the remaining 50% interest in Deerfield SponsorCo and obtained control of the facility.

Upon acquisition of the initial 50% equity interest of Deerfield SponsorCo, the two members each contributed U.S.$1,000 to the capital of Deerfield SponsorCo. On October 12, 2016, third-party construction loan financing was provided to the Deerfield Wind Project in the amount of U.S. $262,900 and a tax equity agreement was executed. Concurrently, each member contributed another U.S. $19,891 to the capital of Deerfield SponsorCo. Construction was completed during the first quarter of 2017 and sale of power to the utility under the power purchase agreement started on February 21, 2017. The interest capitalized during the year ended December 31, 2017 to the investment while the Deerfield Wind Project was under construction amounts to $nil (2016 - $6,072).

On March 14, 2017, the Company acquired the remaining 50% interest in Deerfield SponsorCo for U.S. $21,585 and as a result, obtained control of the facility. The Company accounted for the business combination using the acquisition method of accounting which requires that the fair value of assets acquired and liabilities assumed in the subsidiary be recognized on the consolidated balance sheet as of the acquisition date. It further requires that pre-existing relationships such as the existing development loan between the two parties (note 8(d)) and prior investments of business combinations achieved in stages also be remeasured at fair value. An income approach was used to value these items. A net gain of $nil was recorded on acquisition.

On May 10, 2017, tax equity funding of U.S. $166,595 was received.

The following table summarizes the allocation of the assets acquired and liabilities assumed at the acquisition date:

Working Capital	$	(14,551)
Property, plant and equipment		442,086
Construction loan		(352,666)
Asset retirement obligation		(2,816)
Deferred revenue		(1,556)
Deferred tax liability		(1,979)
Net assets acquired	$	68,518
Cash and cash equivalent	$	4,183
Net assets acquired, net of cash and cash equivalent	$	64,335

(c) Amherst Island Wind Project

Windlectric Inc. ("Windlectric") owns a 75 MW construction-stage wind development project ("Amherst Island Wind Project") in the province of Ontario. On December 20, 2016, Windlectric, a wholly owned subsidiary of the Company at the time, issued fifty percent of its common shares for $50 to a third party and as a result is no longer controlled by APUC. The Company holds an option to acquire the remaining common shares at a fixed price any time prior to January 15, 2019.

Windlectric is considered a VIE namely due to the low level of equity at risk at this point. The Company is not considered the primary beneficiary of Windlectric as the two shareholders have joint control and all decisions must be unanimous. As such, on the transaction date, the Company deconsolidated the assets and liabilities of Windlectric and recorded its retained non-controlling investment in equity and notes receivable and payable at fair value. A net gain of nil was recorded on deconsolidation. The Company is accounting for its investment in the joint venture under the equity method. The interest capitalized during the year ended December 31, 2017 to the investment while the Amherst Island Wind Project is under construction amounts to $1,447 (2016 - $491). As at December 31, 2017, the third-party construction debt of the joint venture was $133,765.

8. Long-term investments (continued)

(c) Amherst Island Wind Project (continued)

As of December 31, 2017, the Company's maximum exposure to loss of $289,374 is comprised of the carrying value of the equity method investment as well as the carrying value of the development loan and outstanding exposure related to credit support as described in note 8(d).

(d) Development loans

The Company entered into 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, or guarantees) in amounts necessary for the continued development and construction of the equity investees' wind projects.

As at December 31, 2017, the Company has a loan and credit support facility with Windlectric of $37,710 (2016 - $29,723). The loan to Windlectric bears interest at an annual rate of 10% on outstanding principal amount and matures on December 31, 2019. The letters of credit are charged an annual fee of 2% on their stated amount. As of December 31, 2017, the following credit support was issued by the Company on behalf of Windlectric: $72,068 letters of credit and guarantees of obligations to the utilities under the PPAs; a guarantee of the obligations under the wind turbine, transmission line, transformer, and other supply agreements; a guarantee of the obligations under the engineering, procurement, and construction management agreements. The initial value of the guarantee obligations is recognized under other long-term liabilities and was valued at $2,449 using a probability weighted discounted cash flow (level 3).

Following acquisition of control of Deerfield SponsorCo (note 8(b)) and Odell SponsorCo LLC (note 8(e)(i)), amounts advanced to the wind project are eliminated on consolidation. The effects of foreign currency exchange rate fluctuations on these advances of a long-term investment nature are recorded in other comprehensive income from the date of acquisition.

No interest revenue is accrued on the loans due to insufficient collateral in the Joint Ventures.

(e) 2016 transactions

i. Odell Wind Facility

Up to September 15, 2016, the Company held a 50% equity interest in Odell SponsorCo LLC, which indirectly owns a 200 MW construction-stage wind development project ("Odell Wind Facility") in the state of Minnesota.

On September 15, 2016, the Company acquired the remaining 50% interest in Odell SponsorCo LLC for U.S. $26,500 and as a result, obtained control of the facility. The Company accounted for the business combination using the acquisition method of accounting, which requires, that the fair value of assets acquired, liabilities assumed and non-controlling interest in the subsidiary, be recognized on the consolidated balance sheets as of the acquisition date. It further requires that pre-existing relationships such as the existing development loan between the two parties (note 8(d)) and prior investments of business combinations achieved in stages also be remeasured at fair value. An income approach was used to value these items. A net gain of nil was recorded on acquisition.

The following table summarizes the allocation of the assets acquired and liabilities assumed at the acquisition date:

Working capital	$	11,836
Property, plant and equipment		469,222
Asset retirement obligation		(4,812)
Deferred tax liability		(4,273)
Non-controlling interest (tax equity investors)		(237,156)
Net assets	$	234,817

ii. Natural gas pipeline developments

During 2016, APUC wrote off an amount of $6,367 representing the total value of its equity interest in the natural gas development projects as both projects have been canceled by the developer.

9. Long-term debt

Long-term debt consists of the following:

Borrowing type	Weighted average coupon	Maturity	Par value	2017	2016
Senior Unsecured Revolving Credit Facilities (a)	—	2018-2022	N/A	**$ 65,017**	$ 242,947
Senior Unsecured Bank Credit Facilities (b)	—	2018-2019	N/A	**169,343**	2,140,122
Commercial Paper (c)		2019	N/A	**6,994**	—
Canadian Dollar Borrowings					
Senior Unsecured Notes (d)	4.61%	2018-2027	$ 785,669	**781,833**	487,389
Senior Secured Project Notes	10.27%	2020-2027	$ 33,568	**33,507**	35,600
U.S. Dollar Borrowings					
Senior Unsecured Notes (e)	4.09%	2020-2047	US$ 1,225,000	**1,527,726**	700,600
Senior Unsecured Utility Notes (f)	5.98%	2020-2035	US$ 227,000	**309,309**	174,206
Senior Secured Utility Bonds (g)	4.95%	2018-2044	US$ 752,500	**969,567**	132,551
				$ 3,863,296	$ 3,913,415
Less: current portion				**(15,511)**	(10,075)
				$ 3,847,785	$ 3,903,340

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 have 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.

Short-term obligations of $264,214 for which the maturity has been extended beyond 12 months subsequent to the end of the year or that are expected to be refinanced using the long-term credit facilities are presented as long-term debt.

Recent financing activities:

(a) Senior unsecured revolving credit facilities

On September 20, 2017, the Company amended the terms of its $65,000 senior unsecured revolving bank credit facility to increase the commitments to $165,000 and extend the maturity from November 19, 2017 to November 19, 2018.

As at December 31, 2017, the Liberty Utilities Group's committed bank lines consisted of a U.S. $200,000 senior unsecured revolving credit facility ("Liberty Credit Facility") and a U.S. $200,000 revolving credit facility at Empire ("Empire Credit Facility") assumed in connection with the acquisition of Empire (note 3(a)). Subsequent to year-end on February 23, 2018, the Liberty Utilities Group' increased commitments under the Liberty Credit Facility to U.S. $500,000 and extended the maturity to February 23, 2023. Concurrent with the amendment to the Liberty Credit Facility, the Liberty Utilities Group closed the Empire Credit Facility.

On October 6, 2017, the Liberty Power Group amended the terms of its $350,000 senior unsecured revolving bank credit facility to increase the commitments to U.S. $500,000 and extended the maturity from July 31, 2019 to October 6, 2022. On October 6, 2017, the St. Damase Wind Facility entered into a $4,000 committed revolving credit facility. The facility matures on October 6, 2020 and is guaranteed by the Liberty Power Group. The facility replaces borrowings that were previously drawn under the Liberty Power Group's senior unsecured revolving credit facility. As at December 31, 2017, $3,900 had been drawn on the facility.

9. Long-term debt (continued)

(a) Senior unsecured revolving credit facilities (continued)

Liberty Power had a $150,000 bilateral revolving credit facility with a maturity date of August 19, 2018. Concurrent with the expansion of the Liberty Power Credit Facility, the Liberty Power Group closed the bilateral credit facility on October 6, 2017.

On December 31, 2017, the Liberty Power Group had an extendible one-year letter of credit facility agreement. The facility provides for issuances of letters of credit up to a maximum of $50,000 and U.S. $30,000. Subsequent to year-end, on February 16, 2018, the Liberty Power Group's increased availability under its revolving letter of credit facility to U.S. $200,000 and extended the maturity to January 31, 2021.

As part of the Park Water System's acquisition on January 8, 2016 (note 3(i)), the Company assumed U.S. $4,250 of debt outstanding under its revolving credit facilities. Shortly after the closing of the acquisition, the Park Water System repaid and closed the revolving credit facilities.

(b) Senior unsecured bank credit facilities

On December 21, 2017, the Company entered into a U.S. $600,000 term credit facility with two Canadian banks maturing on December 21, 2018. On March 7, 2018 the company drew U.S. $600,000 under this facility.

On December 30, 2016, in connection with the acquisition of Empire (note 3(a)), the Company drew U.S. $1,336,440 from the Acquisition Facility it obtained in 2016. The funds drawn were transferred to a paying agent on December 30, 2016 for purposes of distribution to holders of the common shares of Empire (note 3(a)) on January 1, 2017. The total amount of cash held by the paying agent of U.S. $1,495,774 is comprised of this Acquisition Facility draw of U.S. $1,336,440 and cash proceeds received from the initial instalment of convertible debentures (note 14) and is presented as restricted cash on the consolidated balance sheets. Following receipt of the Final Instalment from the convertible debentures on February 7, 2017 (note 14) and the senior notes financing on March 24, 2017 (note 9(d)), the Company fully repaid the Acquisition Facility.

On January 4, 2016, the Company entered into a U.S. $235,000 term credit facility with two U.S. banks. On March 24, 2017, the Company repaid U.S. $100,000 of borrowings under the Corporate Term Credit Facility with proceeds from the closing of the U.S. $750,000 senior unsecured notes (notes 9(e)). In October 2017, the Company extended the maturity on its Corporate Term Credit Facility to July 5, 2019.

As part of the Park Water System's acquisition on January 8, 2016 (note 3(i)), the Company assumed U.S. $22,500 of debt outstanding under a non-revolving term credit facility. In June 2017, this debt was fully repaid and closed.

(c) Commercial Paper

In connection with the acquisition of Empire (note 3(a)), the Company assumed a short-term U.S. $150,000 commercial paper program.

(d) Canadian dollar senior unsecured notes

On January 17, 2017, the Liberty Power Group issued $300,000 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 $99.929 per $100.00 principal amount.

In September 2017, the Company acquired an investment in an equity-investee in exchange for a note payable to the other partner of $669. Repayment of the note is expected in 2019.

(e) U.S. dollar senior unsecured notes

On March 24, 2017, the Liberty Utilities Group 's debt financing entity issued U.S. $750,000 senior unsecured notes in six tranches. The proceeds were applied to repay the Acquisition Facility (note 9(b)) and other existing indebtedness. The notes are of varying maturities from 3 to 30 years with a weighted average life of approximately 15 years and a weighted average coupon of 4.0%. In anticipation of this financing, the Liberty Utilities Group had entered into forward contracts to lock in the underlying U.S. Treasury interest rates. Considering the effect of the hedges, the effective weighted average rate paid by the Liberty Utilities Group will be approximately 3.6%.

9. Long-term debt (continued)

(f) U.S. dollar senior unsecured utility notes

On February 8, 2017, the U.S.$707 Bella Vista Water unsecured notes were fully repaid.

On January 1, 2017, in connection with the acquisition of Empire (note 3(a)), the Company assumed U.S. $102,000 in unsecured utility notes. The notes consist of two tranches, with maturities in 2033 and 2035 with coupons at 6.7% and 5.8%.

(g) U.S. dollar senior secured utility bonds

On January 1, 2017 in connection with the acquisition of Empire (note 3(a)), the Company assumed U.S. $733,000 in secured utility notes. The bonds are secured by a first mortgage indenture and consist of ten tranches with maturities ranging between 2018 and 2044 with coupons ranging from 3.58% to 6.82%.

In June 2017, outstanding bonds payable for the Park Water systems in the amount of U.S. $63,000 were repaid using proceeds from the Mountain Water condemnation discussed in note 23(a). The Company had assumed the U.S. $65,000 of debt outstanding in connection with the acquisition of Park Water in 2016 (note 3(i)).

(h) U.S. dollar senior secured project notes

On March 14, 2017, in connection with the acquisition of Deerfield SponsorCo (note 8(b)), the Company assumed U.S. $262,219 in construction loan. The loans bear interest at an annual rate of 2.33% on any outstanding principal amount. On May 10, 2017, the construction loan was repaid from proceeds received from tax equity (note 8(b)) and cash contributions from APUC.

As of December 31, 2017, the Company had accrued $41,479 in interest expense (2016 - $27,225). Interest expense on the long-term debt in 2017 was $185,339 (2016 - $87,143).

Principal payments due in the next five years and thereafter are as follows:

2018	2019	2020	2021	2022	Thereafter	Total
$ 279,724	$ 179,107	$ 391,025	$ 152,626	$ 492,343	$ 2,331,327	$ 3,826,152

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 2017 were $9,387 (2016 - $5,223).

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. During 2016, the Company permanently froze the accrual of retirement benefits for participants under certain existing plans. Subsequent to the effective date, these employees began accruing benefits under the Company's cash balance plan. 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.

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	
	2017	2016	2017	2016
Change in projected benefit obligation				
Projected benefit obligation, beginning of year	**$ 331,934**	$ 269,382	**$ 83,097**	$ 76,565
Projected benefit obligation assumed from business combination	**344,383**	63,811	**131,263**	9,749
Modifications to pension plan	**—**	(2,754)	**—**	(1,235)
Service cost	**17,869**	8,435	**6,280**	2,916
Interest cost	**27,346**	13,029	**8,621**	3,525
Actuarial (gain) loss	**49,785**	6,773	**13,321**	(2,870)
Contributions from retirees	**—**	—	**2,364**	547
Gain on curtailment	**(1,129)**	—	**(6)**	—
Benefits paid	**(64,605)**	(15,845)	**(8,092)**	(3,230)
Gain on foreign exchange	**(48,546)**	(10,897)	**(14,834)**	(2,870)
Projected benefit obligation, end of year	**$ 657,037**	$ 331,934	**$ 222,014**	$ 83,097
Change in plan assets				
Fair value of plan assets, beginning of year	**236,369**	176,171	**29,139**	18,149
Plan assets acquired in business combination	**247,741**	44,258	**122,900**	10,563
Actual return on plan assets	**82,096**	17,221	**25,612**	1,854
Employer contributions	**38,833**	21,776	**2,683**	2,317
Benefits paid	**(64,605)**	(15,845)	**(5,901)**	(2,683)
Loss on foreign exchange	**(33,686)**	(7,212)	**(10,737)**	(1,061)
Fair value of plan assets, end of year	**$ 506,748**	$ 236,369	**$ 163,696**	$ 29,139
Unfunded status	**$ (150,289)**	$ (95,565)	**$ (58,318)**	$ (53,958)
Amounts recognized in the consolidated balance sheets consists of:				
Non-current assets	**—**	—	**4,938**	—
Current liabilities	**(1,080)**	(436)	**(1,471)**	(1,242)
Non-current liabilities	**(149,209)**	(95,129)	**(61,785)**	(52,716)
Net amount recognized	**$ (150,289)**	$ (95,565)	**$ (58,318)**	$ (53,958)

The accumulated benefit obligation for the pension plans was $614,840 and $317,025 as of December 31, 2017 and 2016, respectively.

On June 22, 2017, all Mountain Water employees were terminated as a result of the condemnation of the Mountain Water assets to the city of Missoula (note 23(a)). The pension and OPEB obligations of these employees remain with the Company. The assets and projected benefit obligations of the plans were revalued at June 30, 2017 and resulted in an actuarial gain of U.S. $2,354 recorded in other comprehensive income and a curtailment gain of U.S. $853 recorded against the loss on long-lived assets.

10. Pension and other post-employment benefits (continued)

(a) Net pension and OPEB obligation (continued)

During 2016, the Company permanently froze the accrual of retirement benefits for participants under certain of the existing plans. The plan amendments resulted in a decrease to the projected benefit obligation of U.S. $2,217 which is recorded as a prior service credit in OCI. In conjunction with the plan amendments, the assets and projected benefit obligations of amended plans were revalued at the closest month-end date which resulted in an actuarial loss of U.S. $8,204 recorded in OCI.

Change in AOCI (before tax)	Pension		OPEB	
	Actuarial losses (gains)	Past service gains	Actuarial losses (gains)	Past service gains
Balance, January 1, 2016	$ 29,461	$ (4,970)	$ (2,338)	$ —
Additions to AOCI	4,479	(2,754)	(3,242)	(1,235)
Amortization in current period	(1,965)	765	(80)	347
Balance at December 31, 2016	$ 31,975	$ (6,959)	$ (5,660)	$ (888)
Additions to AOCI	(3,716)	—	(4,276)	—
Reclassification to regulatory accounts	1,584	—	4,902	—
Amortization in current period	(1,290)	868	321	365
Balance at December 31, 2017	$ 28,553	$ (6,091)	$ (4,713)	$ (523)
Expected amortization in 2018	$ (451)	$ 781	$ 214	$ 328

(b) Assumptions

Weighted average assumptions used to determine net benefit cost for 2017 and 2016 were as follows:

	Pension benefits		OPEB	
	2017	2016	2017	2016
Discount rate	**4.01%**	4.16%	**4.12%**	4.23%
Expected return on assets	**7.01%**	6.41%	**3.88%**	5.50%
Rate of compensation increase	**3.00%**	3.00%	**N/A**	N/A
Health care cost trend rate				
Before Age 65			**6.25%**	6.50%
Age 65 and after			**6.25%**	6.50%
Assumed Ultimate Medical Inflation Rate			**4.75%**	4.75%
Year in which Ultimate Rate is reached			**2023**	2023

10. Pension and other post-employment benefits (continued)

(b) Assumptions (continued)

Weighted average assumptions used to determine net benefit obligation for 2017 and 2016 were as follows:

	Pension benefits		OPEB	
	2017	2016	2017	2016
Discount rate	**3.43%**	3.95%	**3.60%**	4.04%
Rate of compensation increase	**3.00%**	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			**2024**	2023

The mortality assumption for December 31, 2017 was updated to the projected generationally scale MP-2017, adjusted to reflect the ultimate improvement rates in the 2017 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.

The effect of a one percent change in the assumed health care cost trend rate ("HCCTR") for 2017 is as follows. The effects on total service and interest cost of a one percent change in HCCTR excludes the effects of Empire.

		2017
Effect of a 1 percentage point increase in the HCCTR on:		
Year-end benefit obligation	$	38,047
Total service and interest cost		959
Effect of a 1 percentage point decrease in the HCCTR on:		
Year-end benefit obligation	$	(30,057)
Total service and interest cost		(765)

10. Pension and other post-employment benefits (continued)

(c) Benefit costs

The following table lists the components of net benefit costs for the pension plans and OPEB recorded as part of operating expenses 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	
	2017	2016	2017	2016
Service cost	**$ 17,869**	$ 8,435	**$ 6,280**	$ 2,916
Interest cost	**27,346**	13,029	**8,621**	3,525
Expected return on plan assets	**(32,244)**	(14,854)	**(8,312)**	(1,265)
Amortization of net actuarial loss (gain)	**1,480**	1,965	**(299)**	80
Amortization of prior service credits	**(808)**	(765)	**(339)**	(347)
Gain on curtailments and settlements	**(1,394)**	—	**(6)**	—
Amortization of regulatory assets/liability	**15,179**	4,698	**507**	1,471
Net benefit cost	**$ 27,428**	$ 12,508	**$ 6,452**	$ 6,380

(d) 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	70%	49% - 79%
Debt securities	30%	21% - 51%
Other	—%	—%

The fair values of investments as of December 31, 2017, by asset category, are as follows:

Asset Class	Level 1	Percentage
Equity securities	505,219	72%
Debt securities	164,281	27%
Other	945	—%

As of December 31, 2017, the funds do not hold any material investments in APUC.

(e) Cash flows

The Company expects to contribute $26,686 to its pension plans and $4,898 to its post-employment benefit plans in 2018.

The expected benefit payments over the next ten years are as follows:

	2017	2018	2019	2020	2021	2022-2026
Pension plan	$ 43,445	$ 39,037	$ 40,132	$ 45,060	$ 45,108	$ 236,821
OPEB	7,353	7,989	8,845	9,425	10,093	58,844

11. Mandatorily redeemable Series C preferred shares

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 $53,400 per share (fifty-three thousand and four hundred dollars 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 $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:

2018	$	1,068
2019		1,282
2020		1,344
2021		1,364
2022		1,390
Thereafter to 2031		15,761
Redemption amount		5,340
		27,549
Less amounts representing interest		(9,085)
		18,464
Less current portion		(1,068)
	$	17,396

12. Other assets

Other assets consist of the following:

	2017	2016
Income tax receivable	**$ 7,485**	$ 2,951
Deferred financing costs	**4,448**	10,198
Other	**18,633**	6,136
	30,566	19,285
Less current portion	**(8,919)**	(2,951)
	$ 21,647	$ 16,334

13. Other long-term liabilities and deferred credits

Other long-term liabilities consist of the following:

	2017	2016
Advances in aid of construction (a)	**$ 78,636**	$ 105,191
Environmental remediation obligation (b)	**68,147**	63,378
Asset retirement obligations (c)	**55,406**	24,822
Customer deposits (d)	**35,790**	14,881
Unamortized investment tax credits (e)	**22,379**	—
Deferred credits (f)	**26,555**	44,544
Other	**55,779**	22,790
	342,692	275,606
Less current portion	**(57,586)**	(43,157)
	$ 285,106	$ 232,449

(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 2017, $13,626 (2016 - $23,986) 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 historic 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.

The Company estimates the remaining undiscounted, unescalated cost of these MGP-related environmental cleanup activities will be $71,873 (2016 - $76,853) which at discount rates ranging from 2.2% to 2.5% represents the recorded accrual of $68,147 as of December 31, 2017 (2016 - $63,378). Approximately $25,186 is expected to be incurred over the next two years with the balance of cash flows to be incurred over the following 28 years.

Changes in the environmental remediation obligation are as follows:

	2017	2016
Opening Balance	**$ 63,378**	$ 71,529
Remediation activities	**(2,026)**	(1,389)
Accretion	**1,447**	2,464
Changes in cash flow estimates	**2,135**	2,088
Revision in assumptions	**7,686**	(9,101)
Foreign exchange rate adjustment	**(4,473)**	(2,213)
Closing Balance	**$ 68,147**	$ 63,378

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, 2017, the Company has reflected a regulatory asset of $103,761 (2016 - $104,160) for the MGP and related sites (note 7(a)).

13. Other long-term liabilities and deferred credits (continued)

(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) disposal of coal combustion residuals and PCB contaminants and (vi) remove asbestos upon major renovation or demolition of structures and facilities. During the year, APUC assumed asset retirement obligations in connection with the acquisitions of Empire (note 3(a)) and Deerfield SponsorCo (note 8(b)) of $31,717 and $2,816, respectively, recorded additional asset retirement obligations for renewable generation facilities being constructed of $2,604 (2016 - $393), changes in estimates of $1,476 (2016 - $1,022), accretion expense of $2,551 (2016 - $1,055) and settlements of $5,418 (2016 - $nil).

As the cost of retirement of utility assets are expected to be recovered through rates, a corresponding regulatory asset is recorded, as well as the on-going liability accretion and asset depreciation expense (note 7(h)).

(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.

(f) Deferred credits

Deferred credits include unresolved contingent consideration related to prior acquisitions which are expected to be paid and deferred tax credits (note 20).

14. Convertible Unsecured Subordinated Debentures

Maturity date		March 31, 2026
Interest rate		5.00%
Conversion price per share	$	10.60
Receipt of Initial instalment, net of deferred financing costs	$	357,694
Amortization of deferred financing costs		925
Carrying value at December 31, 2016		358,619
Receipt of Final instalment, net of deferred financing costs		743,881
Amortization of deferred financing costs		1,134
Conversion to common shares	$	(1,102,416)
Carrying value at December 31, 2017	$	1,218
Face value at December 31, 2017	$	1,277

On March 1, 2016, the Company completed the sale of $1,150,000 aggregate principal amount of 5.0% convertible debentures.

The convertible debentures were sold on an instalment basis at a price of $1,000 principal amount of debenture, of which $333 was received on closing of the debenture offering and the remaining $667 (the "Final Instalment") was received on February 2, 2017 ("Final Instalment Date") following satisfaction of conditions precedent to the closing of the acquisition of Empire (note 3(a)). The proceeds received from the initial and final instalments, net of financing costs were $357,694 and $743,881, respectively.

14. Convertible Unsecured Subordinated Debentures (continued)

The convertible debentures mature on March 31, 2026 and bore interest at an annual rate of 5% per $1,000 principal amount of convertible debentures until and including the Final Instalment Date, after which the interest rate is 0%. The interest expense recorded for the year ended December 31, 2017 is $9,373 (2016 - $48,205). As the Final Instalment Date occurred prior to the first anniversary of the closing of the debenture offering, holders of the convertible debentures who paid the final instalment by February 2, 2017 received, in addition to the payment of accrued and unpaid interest, a make-whole payment, representing the interest that would have accrued from the day following the Final Instalment Date up to and including March 1, 2017.

The debentures are convertible into up to 108,490,566 common shares. As at December 31, 2017, a total of 108,370,081 common shares of the company were issued (Note 15), representing conversion into common shares of 99.9% of the convertible debentures.

After the Final Instalment Date, any debentures not converted into common shares may be redeemed by the Company at a price equal to their principal amount plus any unpaid interest, which accrued prior to and including the Final Instalment Date. At maturity, the Company will have the right to pay the principal amount due in cash or in common shares. In the case of common shares, such shares will be valued at 95% of their weighted average trading price on the Toronto Stock Exchange for the 20 consecutive trading days ending five trading days preceding the maturity date.

15. Shareholders' capital

(a) Common shares

Number of common shares:

	2017	2016
Common shares, beginning of year	**274,087,018**	255,869,419
Public offering (i) and subscription receipts (ii)	**43,470,000**	12,938,457
Conversion of convertible debentures (note 14)	**108,370,081**	—
Dividend reinvestment plan (iii)	**3,905,848**	2,322,618
Exercise of share-based awards (c)	**1,932,988**	2,956,524
Common shares, end of year	**431,765,935**	274,087,018

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 2019. 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

On November 10, 2017, APUC issued 43,470,000 common shares at $13.25 per share pursuant to a public offering for proceeds of $576,000 before issuance costs of $24,342 or $17,895 net of taxes.

(ii) Subscription receipts

On December 29, 2014, the Company received total proceeds of $77,503 from the issuance to Emera Inc. ("Emera") of 8,708,170 subscription receipts at a price of $8.90 per share in connection with the Odell SponsorCo investment (note 8(c)). Effective June 30, 2016, Emera converted the subscription receipts for no additional consideration on a one-for-one basis into common shares and received 661,693 additional common shares in lieu of dividends declared during the holding period.

15. Shareholders' capital (continued)

(a) Common shares (continued)

(ii) Subscription receipts (continued)

On December 29, 2014, the Company received total proceeds of $33,000 from the issuance to Emera of 3,316,583 subscription receipts at a price of $9.95 per share in connection with the Park Water System acquisition (note 3(i)). Effective June 30, 2016, Emera converted the subscription receipts for no additional consideration on a one-for-one basis into common shares and received 252,011 additional common shares in lieu of dividends declared during the holding period.

(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 1,063,572 common shares under the dividend reinvestment plan.

(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, 2017 and 2016:

Preferred shares	Number of shares	Price per share	Carrying amount
Series A	**4,800,000**	**$ 25**	**$ 116,546**
Series D	**4,000,000**	**$ 25**	**97,259**
			$ 213,805

The holders of Series A and Series D preferred shares are entitled to receive fixed cumulative preferential dividends as and when declared by the Board at an annual amount of $1.125 and $1.25 per share, respectively, for each year up to, but excluding December 31, 2018 and March 31, 2019, respectively. The Series A and Series D dividend rate will reset on those dates and every five years thereafter at a rate equal to the then five-year Government of Canada bond yield plus 2.94% and 3.28%, respectively. The Series A and Series D preferred shares are redeemable at $25 per share at the option of the Company on December 31, 2018 and March 31, 2019, respectively, and every fifth year thereafter.

The holders of Series A and Series D preferred shares have 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. The Series B and Series E preferred shares will be entitled to receive quarterly floating-rate cumulative dividends, as and when declared by the Board, at a rate equal to the then ninety-day Government of Canada treasury bill yield plus 2.94% and 3.28%, respectively. The holders of Series B and Series E preferred shares will have the right to convert their shares back into Series A and Series D preferred shares on December 31, 2018 and March 31, 2019, respectively and every fifth year thereafter. The Series A, Series B, Series D and Series E preferred shares do not have a fixed maturity date and are not redeemable at the option of the holders thereof.

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 11).

15. Shareholders' capital (continued)

(c) Share-based compensation

For the year ended December 31, 2017, APUC recorded $10,804 (2016 - $5,675) in total share-based compensation expense detailed as follows:

	2017	2016
Share options	**$ 3,990**	$ 3,006
Directors deferred share units	**771**	683
Employee share purchase	**568**	238
Performance share units	**5,475**	1,748
Total share-based compensation	**$ 10,804**	$ 5,675

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, 2017, total unrecognized compensation costs related to non-vested options and PSUs were $2,796 and $8,471, respectively, and are expected to be recognized over a period of 1.61 and 1.84 years, respectively.

(i) Share option plan

The Company's share option plan (the "Plan") permits the grant of share options to key 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 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 which 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.

In the case of qualified retirement, the Board may accelerate the vesting of the unvested options then held by the optionee at the Board's discretion. All vested options may be exercised within ninety days after retirement. In the case of death, the options vest immediately and the period over which the options can be exercised is one year. In the case of disability, options continue to vest and be exercisable in accordance with the terms of the grant and the provisions of the plan. Employees have up to thirty days to exercise vested options upon resignation or termination.

In the event that the Company restates its financial results, any unpaid or unexercised options may be cancelled at the discretion of the Board (or the compensation committee of the Board ("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 adjusted 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.

15. Shareholders' capital (continued)

(c) Share-based compensation (continued)

(i) Share option plan (continued)

The following assumptions were used in determining the fair value of share options granted:

	2017	2016
Risk-free interest rate	**1.4%**	**0.9%**
Expected volatility	**25%**	**23%**
Expected dividend yield	**4.3%**	**4.5%**
Expected life	**5.50 years**	**5.50 years**
Weighted average grant date fair value per option	**$ 1.45**	**$ 1.26**

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 at January 1, 2016	7,164,652	$ 6.92	4.74	$ 28,561
Granted	2,596,025	10.85	8.00	—
Exercised	(3,715,663)	5.25	2.06	20,790
Balance at December 31, 2016	6,045,014	$ 9.64	6.27	$ 10,595
Granted	2,328,343	12.82	8.00	
Exercised	(1,634,501)	7.81	3.76	7,696
Balance at December 31, 2017	6,738,856	$ 11.18	6.32	$ 19,380
Exercisable at December 31, 2017	2,448,689	$ 10.03	5.61	$ 9,473,719

(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 (a) 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, for Canadian employees, and (b) 15% of the employee contribution amount for the first fifteen thousand dollar per employee contributed annually, for U.S. employees. 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 contribution 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 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, 2017, a total of 283,523 common shares (2016 - 144,264) were issued to employees under the ESPP.

15. Shareholders' capital (continued)

(c) Share-based compensation (continued)

(iii) Directors 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, 2017, 293,906 (2016 - 224,663) 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.

(iv) Performance share units

The Company offers a PSU plan to its employees as part of the Company's long-term incentive program. PSUs are granted annually for three-year overlapping performance cycles. 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. Dividends accumulating during the vesting period are converted to PSUs 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 have voting rights. Any PSUs not vested at the end of a performance period will expire. The PSUs 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. The aggregate number of common shares reserved for issuance from treasury by APUC under the PSU 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 balance sheet date. Compensation cost recognized is adjusted to reflect the performance conditions estimated to-date.

A summary of the PSUs follows:

	Number of awards	Weighted average grant-date fair value	Weighted average remaining contractual term (years)	Aggregate intrinsic value
Balance at January 1, 2016	564,116	$ 7.59	1.63	$ 6,155
Granted, including dividends	219,315	11.62	2.00	—
Exercised	(181,875)	8.29	—	2,115
Forfeited	(22,568)	9.64	—	—
Balance at December 31, 2016	578,988	$ 9.82	1.74	$ 6,595
Granted, including dividends	811,974	13.54	2.00	—
Exercised	(374,973)	8.33	—	4,394
Forfeited	(60,961)	12.61	—	—
Balance at December 31, 2017	955,028	$ 12.30	1.84	$ 13,428
Exercisable at December 31, 2017	172,031	$ 9.75	—	$ 2,423

16. Accumulated Other comprehensive income (loss)

AOCI consists of the following balances, net of tax:

	Foreign currency cumulative translation	Unrealized gain on cash flow hedges	Net change on available-for-sale investments	Pension and post-employment actuarial changes	Total
Balance, January 1, 2016	$ 261,357	$ 39,329	$ (72)	$ (13,877)	$ 286,737
OCI (loss) before reclassifications	(61,029)	34,308	213	2,856	(23,652)
Amounts reclassified	—	(7,554)	—	(604)	(8,158)
Net current period OCI	(61,029)	26,754	213	2,252	(31,810)
Balance, December 31, 2016	$ 200,328	$ 66,083	$ 141	$ (11,625)	$ 254,927
OCI before reclassifications	(200,400)	8,714	—	838	(190,848)
Amounts reclassified	—	(6,805)	(141) —	(313)	(7,259)
Net current period OCI	$ (200,400)	$ 1,909	$ (141)	$ 525	$ (198,107)
Balance, December 31, 2017	$ (72)	$ 67,992	$ —	$ (11,100)	$ 56,820

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 administrative expenses.

17. Dividends

All dividends of the Company are made on a discretionary basis as determined by the Board. The Company declares and pays the dividend on its commons shares in U.S. dollars. Dividends declared in Canadian equivalent dollars during the year were as follows:

	2017		2016	
	Dividend	Dividend per share	Dividend	Dividend per share
Common shares	**$ 242,509**	**$ 0.6084**	$ 149,158	$ 0.5452
Series A preferred shares	**$ 5,400**	**$ 1.1250**	$ 5,400	$ 1.1250
Series D preferred shares	**$ 5,000**	**$ 1.2500**	$ 5,000	$ 1.2500

18. Related party transactions

Emera Inc.

An executive at Emera was a member of the Board of APUC until June 8, 2017. The Energy Services Business sold electricity to Maine Public Service Company, and Bangor Hydro, both of which are subsidiaries of Emera. The portion considered related party transactions during 2017 amounts to U.S. $4,397 (2016 - U.S. $10,185). The Liberty Utilities Group purchased natural gas from Emera for its gas utility customers. The portion considered related party transactions amounts to U.S. $1,006 (2016 - U.S. $3,939). Both the sale of electricity to Emera and the purchase of natural gas from Emera followed a public tender process, the results of which were approved by the regulator in the relevant jurisdiction. In 2016, a subsidiary of the Company and Emera Utility Services Inc. entered into a design, engineering, supply and construction agreement for the Tinker transmission upgrade project. The transmission upgrade was placed in service in Q2 2017 with final completion of the contract work in the fourth quarter. The total cost of the contract was $9,500. The contract followed a market based request for proposal process. On October 14, 2016, APUC paid $680 to Emera as reimbursement for professional services incurred and accrued in 2014.

There was U.S. $1,467 included in accruals in 2017 (2016 - U.S. $757) related to these transactions at the end of the year.

18. Related party transactions (continued)

Equity-method investments

The Company provides administrative services to its equity-method investees and is reimbursed for incurred costs. To that effect, the Company charged its equity-method investees $5,969 (2016 - $3,313) during the year.

Trafalgar

In 2016, the Company received U.S. $10,083 in proceeds from the settlement of the Trafalgar matter, and paid U.S. $2,900 to an entity partially and indirectly owned by Senior Executives as its proportionate share. The gain to APUC, net of legal and other liabilities, of approximately U.S. $6,600 was recorded in 2016.

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 18MW 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.

19. Non-controlling interests and Redeemable non-controlling interest

Net loss attributable to non-controlling interests for the years ended December 31 consists of the following:

	2017	2016
HLBV and other adjustments attributable to:		
Non-controlling interest -Class A partnership units	**$ (52,020)**	$ (35,451)
Non-controlling interest -redeemable Class A partnership units	**(13,400)**	(4,952)
Other net earnings attributable to non-controlling interests	**3,172**	1,853
Net effect of non-controlling interests	**$ (62,248)**	$ (38,550)

The non-controlling Class A membership equity investors ("Class A 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(r).

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 discussed in note 20 will be used in the calculation of HLBV beginning in 2018.

Non-controlling interest

As of December 31, 2017, non-controlling interests of $756,007 (2016 - $562,358) includes Class A partnership units held by tax equity investors in certain U.S. wind power and solar generating facilities of $754,932 (2016 - $561,308) and other non-controlling interests of $1,075 (2016 - $1,050). Contributions from new Class A partnership investors of U.S. $42,750 was received for the Great Bay Solar Facility in 2017 (note 3(c)); U.S. $9,800 was received for the Bakersfield II Solar Facility on February 28, 2017 (note 3(g)); and, U.S. $166,595 was received for the Deerfield Wind Project on May 10, 2017 (note 8(b)).

19. Non-controlling interests and Redeemable non-controlling interest (continued)

Redeemable Non-controlling interest

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. The redeemable non-controlling interests in subsidiaries balance is determined using the hypothetical liquidation at book value method subsequent to initial recognition, however, if the redemption amount is probable or currently redeemable, the Company records the instruments at their redemption value. Redemption is not considered probable as of December 31, 2017. Changes in redeemable non-controlling interest are as follows:

	2017	2016
Opening balance	**$ 29,434**	$ 25,751
Net loss attributable to redeemable non-controlling interest	**(13,400)**	(4,952)
Contributions from redeemable non-controlling interests (note 3(f))	**40,797**	10,171
Dividends declared and distributions to redeemable non-controlling interest	**(1,454)**	(590)
Foreign exchange	**(3,249)**	(946)
Closing balance	**$ 52,128**	$ 29,434

Contributions from new Class A partnership investors of U.S. $31,212 was received for the Luning Solar Facility on on February 17, 2017 (note 3(f)).

20. 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% (2016 - 26.5%). The differences are as follows:

	2017	2016
Expected income tax expense at Canadian statutory rate	**$ 59,907**	$ 34,317
Increase (decrease) resulting from:		
Effect of differences in tax rates on transactions in and within foreign jurisdictions and change in tax rates	**(27,671)**	(11,363)
Non-controlling interests share of income	**24,708**	13,973
Allowance for equity funds used during construction	**(1,029)**	(1,100)
Capital gain rate differential	**(919)**	(3,612)
Goodwill divestiture and permanent basis differences associated with Mountain Water condemnation	**7,059**	—
Non-deductible acquisition costs	**18,091**	1,996
Change in valuation allowance	**(1,304)**	2,841
Tax credits	**(8,162)**	(477)
Adjustment relating to prior periods	**(30)**	(711)
U.S. tax reform	**22,390**	—
Other	**2,154**	1,272
Income tax expense	**$ 95,194**	$ 37,136

On December 22, 2017, the US Tax Cuts and Jobs Act of 2017 (the Act) was signed into legislation. The Act includes a broad range of legislative changes including a reduction of the US federal corporate income tax rate from 35% to 21% effective January 1, 2018, limitations on the deductibility of interest and 100% expensing of qualified property. The Act provides an exemption to regulated utilities from the limitations on the deductibility of interest and also does not permit regulated utilities to immediately expense 100% of the cost of new investments in qualified property.

20. Income taxes (continued)

As a result of the Act being enacted during 2017, the Company is required to revalue its United States deferred income tax assets and liabilities based on the rates they are expected to reverse at in the future, which is generally 21% for U.S. federal tax purposes. The company was able to make reasonable estimates of the impact of the Act and has recorded provisional amounts for the remeasurement of deferred taxes. The Company has recognized a provisional charge to income tax expense of $22,390 in 2017 as a result of the revaluation of its U.S. non-regulated net deferred income tax assets. The Company has also reduced its regulated net deferred income tax liabilities by a provisional amount of $411,409 and recorded an equivalent increase to net regulatory liability since the benefit of lower U.S. taxes is probable of being returned to customers by order of the applicable regulator.

The Company is still analyzing certain aspects of the Act, which could potentially affect the measurement of these balances or potentially give rise to new deferred tax amounts. Further adjustments, if any, will be recorded by the Company during the measurement period in 2018 as permitted by SEC Staff Accounting Bulletin 118, Income tax Accounting Implications of the Tax Cuts and Jobs Act.

For the years ended December 31, 2017 and 2016, earnings from continuing operations before income taxes consist of the following:

		2017		2016
Canadian operations	**$**	**(3,269)**	$	29
U.S. operations		**229,309**		129,481
	$	**226,040**	$	129,510

Income tax expense (recovery) attributable to income (loss) consists of:

		Current		Deferred		Total
Year ended December 31, 2017						
Canada	**$**	**4,277**	**$**	**(18,390)**	**$**	**(14,113)**
United States		**5,631**		**103,676**		**109,307**
	$	**9,908**	**$**	**85,286**	**$**	**95,194**
Year ended December 31, 2016						
Canada	$	7,533	$	(10,501)	$	(2,968)
United States		928		39,176		40,104
	$	8,461	$	28,675	$	37,136

20. 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, 2017 and 2016 are presented below:

	2017	2016
Deferred tax assets:		
Non-capital loss, investment tax credits, currently non-deductible interest expenses, and financing costs	**$ 412,327**	$ 459,436
Pension and OPEB	**54,744**	57,751
Acquisition-related costs	**2,008**	3,612
Environmental obligation	**18,570**	25,683
Reserves and other non-deductible costs	**38,453**	11,390
Regulatory liabilities	**193,942**	76,315
Other	**20,555**	14,374
Total deferred income tax assets	**740,599**	648,561
Less valuation allowance	**(15,486)**	(21,656)
Total deferred tax assets	**725,113**	626,905
Deferred tax liabilities:		
Property, plant and equipment	**(838,110)**	(562,124)
Intangible assets	**(8,067)**	(8,035)
Outside basis in partnership	**(157,463)**	(187,717)
Regulatory accounts	**(143,090)**	(108,506)
Financial derivatives	**(1,230)**	(17,649)
Other	**—**	(1,008)
Total deferred tax liabilities	**(1,147,960)**	(885,039)
Net deferred tax liabilities	**$ (422,847)**	$ (258,134)
Consolidated Balance Sheets Classification:		
Deferred tax assets	**$ 76,972**	$ 30,005
Deferred tax liabilities	**(499,819)**	$ (288,139)
Net deferred tax liabilities	**$ (422,847)**	$ (258,134)

The valuation allowance for deferred tax assets as at December 31, 2017 was $15,486 (2016 - $21,656). 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, 2017, the Company had non-capital losses carried forward available to reduce future year's taxable income, which expire as follows:

Year of expiry	Non-capital loss carryforwards
2020 and onwards	$ 1,247,448

The Company has provided for deferred income taxes for the estimated tax cost of distributed earnings of its subsidiaries. Deferred income taxes have not been provided on approximately $188,348 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.

21. 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 subscription receipts outstanding (note 15 (a)). 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 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. The convertible debentures (note 14) are convertible into common shares at any time after the Final Instalment Date, but prior to maturity or redemption by the Company. The Final Instalment Date occurred on February 2, 2017, and as such, the shares issuable upon conversion of the convertible debentures are included in diluted earnings per share beginning on that date.

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:

		2017		2016
Net earnings attributable to shareholders of APUC	**$**	**193,094**	$	130,924
Series A Preferred shares dividend		**5,400**		5,400
Series D Preferred shares dividend		**5,000**		5,000
Net earnings attributable to common shareholders of APUC from continuing operations – Basic and Diluted	**$**	**182,694**	$	120,524
Weighted average number of shares				
Basic		**382,323,434**		271,832,430
Effect of dilutive securities		**3,662,714**		2,244,602
Diluted		**385,986,148**		274,077,032

The shares potentially issuable as a result of 2,328,343 share options (2016 - 1,665,131) are excluded from this calculation as they are anti-dilutive.

22. Segmented information

In connection with the acquisition of Empire on January 1, 2017, the Company aligned its management reporting under two primary North American business units consisting of the Liberty Power Group and the Liberty Utilities Group. The two business units are the two segments of the Company.

The Liberty Power Group owns and operates a diversified portfolio of non-regulated renewable and thermal electric generation utility assets; the Liberty Utilities Group owns and operates a portfolio of regulated electric, natural gas, water distribution and wastewater collection utility systems and transmission operations.

For purposes of evaluating divisional performance, the Company allocates the realized portion of any gains or losses on financial instruments to specific divisions. The unrealized portion of any gains or losses on derivative instruments not designated in a hedging relationship is not considered in management's evaluation of divisional performance and is therefore allocated and reported in the corporate segment. The results of operations and assets for these segments are reflected in the tables below. The comparative information for 2016 has been reclassified to conform with the composition of the reporting segments presented in the current year.

	Year ended December 31, 2017			
	Liberty Power Group	Liberty Utilities Group	Corporate	Total
Revenue	$ 300,173	$ 1,677,636	$ —	$ 1,977,809
Fuel, power and water purchased	25,384	485,016	—	510,400
Net revenue	274,789	1,192,620	—	1,467,409
Operating expenses	86,675	511,983	—	598,658
Administrative expenses	20,777	42,900	789	64,466
Depreciation and amortization	103,038	222,088	1,321	326,447
Gain on foreign exchange	—	—	373	373
Operating income	64,299	415,649	(2,483)	477,465
Interest expense	47,565	126,790	28,276	202,631
Interest, dividend, equity and other income	(3,723)	(5,449)	(2,817)	(11,989)
Other expenses (gain)	2,282	(4,250)	62,751	60,783
Earnings (loss) before income taxes	$ 18,175	$ 298,558	$ (90,693)	$ 226,040
Property, plant and equipment	$ 2,818,697	$ 5,047,454	$ 43,342	$ 7,909,493
Equity-method investees	37,273	2,784	422	40,479
Total assets	3,103,999	7,299,576	130,060	10,533,635
Capital expenditures	211,328	528,695	—	740,023

22. Segmented information (continued)

	Year ended December 31, 2016			
	Liberty Power Group	Liberty Utilities Group	Corporate	Total
Revenue	$ 265,949	$ 830,069	$ —	$ 1,096,018
Fuel and power purchased	21,260	274,055	—	295,315
Net revenue	244,689	556,014	—	800,703
Operating expenses	72,346	260,595	60	333,001
Administrative expenses	19,656	26,272	421	46,349
Depreciation and amortization	80,094	105,448	1,357	186,899
Gain on foreign exchange	—	—	(436)	(436)
Operating income	72,593	163,699	(1,402)	234,890
Interest expense	21,847	50,671	59,074	131,592
Interest, dividend and other income	32	(5,282)	(5,323)	(10,573)
Other expense (gain)	(14,403)	(11,690)	10,454	(15,639)
Earnings (loss) before income taxes	$ 65,117	$ 130,000	$ (65,607)	$ 129,510
Property, plant and equipment	$ 2,455,336	$ 2,390,047	$ 44,563	$ 4,889,946
Equity-method investees	59,021	2,314	3,084	64,419
Total assets	2,771,651	5,388,966	88,843	8,249,460
Capital expenditures	141,420	264,323	—	405,743

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.

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:

	2017	2016
Revenue		
Canada	**$ 95,326**	$ 100,403
United States	**1,882,483**	995,615
	$ 1,977,809	$ 1,096,018
Property, plant and equipment		
Canada	**$ 568,693**	$ 558,271
United States	**7,340,800**	4,331,675
	$ 7,909,493	$ 4,889,946
Intangible assets		
Canada	**$ 34,654**	$ 36,611
United States	**29,454**	28,378
	$ 64,108	$ 64,989

Revenue is attributed to the two countries based on the location of the underlying generating and utility facilities.

23. 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 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.

Condemnation Expropriation Proceedings

Mountain Water was the subject of a condemnation lawsuit filed by the city of Missoula. On August 2, 2016, the Supreme Court of Montana upheld the District Court's decision that the city of Missoula could proceed with condemnation of Mountain Water's assets. The fair market value of the condemned property as of May 6, 2014 was assessed by the Commissioners to be U.S. $88,600. Upon taking possession of Mountain Water's assets on June 22, 2017, the city of Missoula paid U.S. $83,863 to Mountain Water, net of closing adjustments and amounts required to be paid by the City directly to various developers in satisfaction of obligations under Funded By Other (FBO) contracts relating to the assets.

In connection with Liberty Utilities' indirect acquisition of Mountain Water in January 2016, Liberty Utilities was permitted and continues to hold-back U.S. $14,400 from the purchase price otherwise payable to Carlyle Infrastructure Partners, L.P. ("Carlyle") and certain other interest holders.

The condemnation of the Mountain Water assets resulted in a gain on long-lived assets of U.S. $4,370.

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.

(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, 2017.

APUC has outstanding purchase commitments for power purchases, gas delivery, service and supply, service agreements, capital project commitments and operating leases.

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)	$ 74,025	$ 48,344	$ 49,940	$ 50,214	$ 50,495	$ 254,380	$ 527,398
Gas supply and service agreements (ii)	91,425	66,848	51,809	33,161	28,411	97,489	369,143
Service agreements	47,695	47,211	48,529	48,827	46,548	435,093	673,903
Capital projects	41,054	17,064	65	65	65	16	58,329
Operating leases	9,573	8,974	8,298	8,361	9,718	225,047	269,971
Total	$ 263,772	$ 188,441	$ 158,641	$ 140,628	$ 135,237	$ 1,012,025	$ 1,898,744

23. Commitments and contingencies (continued)

(b) Commitments (continued)

(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, 2017. 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.

24. Non-cash operating items

The changes in non-cash operating items consist of the following:

	2017	2016
Accounts receivable	**$ (18,502)**	$ 6,612
Fuel and natural gas in storage	**(1,970)**	6,877
Supplies and consumable inventory	**1,392**	692
Income taxes receivable	**1,674**	145
Prepaid expenses	**(897)**	(6,161)
Accounts payable	**(23,178)**	24,524
Accrued liabilities	**25,122**	(9,454)
Current income tax liability	**(3,432)**	(4,552)
Net regulatory assets and liabilities	**(54,235)**	(14,979)
	$ (74,026)	$ 3,704

25. Financial instruments

(a) Fair value of financial instruments

2017	Carrying amount	Fair Value	Level 1	Level 2	Level 3
Notes receivable	$ 41,873	$ 47,912	$ —	$ 47,912	$ —
Derivative instruments (1):					
Energy contracts designated as a cash flow hedge	79,490	79,490	—	—	79,490
Energy contracts not designated as a cash flow hedge	137	137	—	137	—
Commodity contracts for regulated operations	92	92	—	92	—
Transmission congestion rights	7,812	7,812	—	7,812	—
Total derivative instruments	87,531	87,531	—	8,041	79,490
Total financial assets	$ 129,404	$ 135,443	$ —	$ 55,953	$ 79,490
Long-term debt	$ 3,863,296	$ 4,093,071	$ 817,895	$ 3,275,176	$ —
Convertible debentures	1,218	1,277	1,277	—	—
Preferred shares, Series C	18,464	18,973		18,973	—
Derivative instruments:					
Energy contracts designated as a cash flow hedge	97	97	—	—	97
Energy contracts not designated as a cash flow hedge	39	39	—	39	—
Cross-currency swap designated as a net investment hedge	72,023	72,023	—	72,023	—
Interest rate swap designated as a hedge	10,613	10,613	—	10,613	—
Currency forward contract not designated as a hedge	432	432	—	432	—
Commodity contracts for regulated operations	3,286	3,286	—	3,286	—
Total derivative instruments	86,490	86,490	—	86,393	97
Total financial liabilities	$ 3,969,468	$ 4,199,811	$ 819,172	$ 3,380,542	$ 97

(1) Balance of $553 associated with certain weather derivatives have been excluded, as they are accounted for based on intrinsic value rather than fair value.

25. Financial instruments (continued)

(a)Fair value of financial instruments (continued)

2016	Carrying amount	Fair Value	Level 1	Level 2	Level 3
Notes receivable	$ 38,183	$ 47,933	$ —	$ 47,933	$ —
Derivative instruments (1):					
Energy contracts designated as a cash flow hedge	84,554	84,554	—	—	84,554
Interest rate swap designated as a hedge	48,093	48,093	—	48,093	—
Currency forward contract not designated as a hedge	17,864	17,864	—	17,864	—
Commodity contracts for regulatory operations	359	359	—	359	—
Total derivative instruments	150,870	150,870	—	66,316	84,554
Total financial assets	$ 189,053	$ 198,803	$ —	$ 114,249	$ 84,554
Long-term debt	$ 3,913,415	$ 3,999,266	$ 517,637	$ 3,481,629	$ —
Convertible debentures	358,619	455,975	455,975	—	—
Preferred shares, Series C	18,460	18,613	—	18,613	—
Derivative instruments:					
Cross-currency swap designated as a net investment hedge	95,404	95,404	—	95,404	—
Interest rate swaps designated as a hedge	13,385	13,385	—	13,385	—
Commodity contracts for regulated operations	36	36	—	36	—
Total derivative instruments	108,825	108,825	—	108,825	—
Total financial liabilities	$ 4,399,319	$ 4,582,679	$ 973,612	$ 3,609,067	$ —

(1) Balance of $314 associated with certain weather derivatives have been excluded, as they are accounted for based on intrinsic value rather than fair value.

25. Financial instruments (continued)

(a) Fair value of financial instruments (continued)

The Company has determined that the carrying value of its short-term financial assets and liabilities approximates fair value as of December 31, 2017 and 2016 due to the short-term maturity of these instruments.

Notes receivable fair values (level 2) have been 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 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 derivative instruments primarily consist of swaps, options, rights and forward physical deals 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. Transmission congestion rights positions are fair valued using the most recent monthly auction clearing prices.

The Company's level 3 instruments consist of energy contracts for electricity sales. The significant unobservable inputs used in the fair value measurement of energy contracts are the internally developed forward market prices ranging from $22.13 to $121.56 with a weighted average of $33.20 as of December 31, 2017. The processes and methods of measurement are developed using the market knowledge of the trading operations within the Company and are derived from observable energy curves adjusted to reflect the illiquid market of the hedges and, in some cases, the variability in deliverable energy. Significant increases (decreases) in any of these inputs in isolation would result in a significantly lower (higher) fair value measurement. The change in the fair value of the energy contracts is detailed in notes 25(b)(ii) and 25(b)(iv).

Fair value estimates are made at a specific point in time, using available information about the financial instrument. These estimates are subjective in nature and often cannot be determined with precision.

The Company's accounting policy is to recognize transfers between levels of the fair value hierarchy on the date of the event or change in circumstances that caused the transfer. There was no transfer into or out of level 1, level 2 or level 3 during the years ended December 31, 2017 and 2016.

(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:

	2017
Financial contracts: Swaps	2,518,812
Options	518,866
Forward contracts	12,420,000
	15,457,678

25. Financial instruments (continued)

(b) Derivative instruments (continued)

(i) Commodity derivatives – regulated accounting (continued)

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 settlement of these contracts are included in the calculation of deferred gas costs (note 7(d)). 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.

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:

	2017		2016	
Regulatory assets:				
Swap contracts	U.S. **$**	**—**	U.S. $	—
Option contracts	U.S. **$**	**—**	U.S. $	27
Forward contracts	U.S. **$**	**6,319**	U.S. $	—
Regulatory liabilities:				
Swap contracts	U.S. **$**	**287**	U.S. $	175
Option contracts	U.S. **$**	**138**	U.S. $	92
Forward contracts	U.S. **$**	**20,909**	U.S. $	—

(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)
688,147	December 2023	U.S. $	40.40	PJM Western HUB
2,926,922	December 2023	U.S. $	29.26	NI HUB
3,330,876	December 2027	U.S. $	36.46	ERCOT North HUB

On October 25, 2016, the Company entered into forward contracts to purchase U.S. $250,000 10-year U.S. Treasury bills at an interest rate of 1.8395% and U.S. $250,000 30-year U.S. Treasury bills at an interest rate of 2.5539% settling on February 13, 2017 in order to reduce the interest rate risk related to the probable issuance on that date of U.S. $500,000 bonds in relation to the acquisition of Empire (note 9(e)). The change in fair value to February 13, 2017 resulted in a gain of U.S. $36,667. The effective portion of the hedge of U.S. $718 for the year ended December 31, 2017 was recorded in OCI while the ineffective portion was recorded in the consolidated statement of operations.

The Company is 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 $135,000 bond. The change in fair value resulted in a gain of $2,771 for the year ended December 31, 2017 (2016 - loss of $3,726), which is recorded in OCI.

25. Financial instruments (continued)

(b) Derivative instruments (continued)

(ii) Cash flow hedges (continued)

The following table summarizes OCI attributable to derivative financial instruments designated as a cash flow hedge:

	2017	2016
Effective portion of cash flow hedge, gain	**$ 8,714**	$ 34,355
Amortization of cash flow hedge	**(30)**	(47)
Gain reclassified from AOCI	**(6,775)**	(7,554)
OCI attributable to shareholders of APUC	**$ 1,909**	$ 26,754

The Company expects $11,612 and $2,643 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 U.S. based operations. APUC manages this risk primarily through the use of natural hedges by using U.S. long-term debt to finance its U.S. operations and a combination of foreign exchange forward contracts and spot purchases. APUC only enters into foreign exchange forward contracts with major Canadian financial institutions having a credit rating of A or better, thus reducing credit risk on these forward contracts.

The Company designates the amounts drawn on the Liberty Power Group's revolving credit facility denominated in U.S. dollars in excess of the principal amount on the USD loans receivable from its equity investees as a hedge of the foreign currency exposure of its net investment in the Liberty Power Group's U.S. operations. 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 $21,648 for the year ended December 31, 2017 (2016 - nil) was recorded in OCI.

Concurrent with its $150,000, $200,000 and $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 Liberty Power 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 $23,381 (2016 - $6,156) was recorded in OCI in 2017.

(iv) Other derivatives

The Company provides energy requirements to various customers under contracts at fixed rates. While the production from the Tinker Hydroelectric Facility are 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 though the use of short-term financial forward energy purchase contracts which 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.

25. Financial instruments (continued)

(b) Derivative instruments (continued)

(iv) Other derivatives (continued)

The Company is exposed to interest rate fluctuations related to certain of its floating rate debt obligation, 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 currently hedges some of that risk (note 25(b)(ii)).

The Company is exposed to foreign exchange fluctuations related to U.S dollar denominated development loans from projects accounted for as equity investments (note 8(d)). This risk was mitigated through the use of currency forward contracts to sell U.S. $38,400 for $47,225 between July 29, 2016 and September 29, 2016. As of December 31, 2017, these instruments had settled. This currency forward contract was not accounted for as a hedge.

The Company was exposed to foreign exchange fluctuations related to the acquisition of the Empire shares denominated in U.S dollar (note 3(a)). This risk was mitigated through the conversion to U.S. dollars of $359,950 from the proceeds received on the initial instalment of convertible unsecured subordinated debentures (note 14) and the use of a currency forward contract to buy an amount of U.S. $567,665 for $744,050 on January 31, 2017. This currency forward contract was not accounted for as a hedge. The settlement of the currency forward contract resulted in a total realized loss of $16,412 for the year ended December 31, 2017, which is recorded as a loss on foreign exchange in the consolidated statements of operations (2016 - gain of $17,684).

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, 2017, a loss on foreign exchange of $432 (2016 - $nil) 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 and for the ineffective portion of gains and losses on derivatives that are accounted for 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:

		2017		2016
Change in unrealized loss (gain) on derivative financial instruments:				
Energy derivative contracts	**$**	**(52)**	$	(426)
Currency forward contract		**432**		(19,810)
Commodity contracts		**(3,916)**		—
Total change in unrealized gain on derivative financial instruments	**$**	**(3,536)**	$	(20,236)
Realized loss (gain) on derivative financial instruments:				
Interest rate swaps		**(193)**		—
Energy derivative contracts		**730**		951
Currency forward contract		**16,413**		(1,371)
Total realized loss (gain) on derivative financial instruments	**$**	**16,950**	$	(420)
Loss (gain) on derivative financial instruments not accounted for as hedges		**13,414**		(20,656)
Ineffective portion of derivative financial instruments accounted for as hedges		**805**		1,518
	$	**14,219**	$	(19,138)
Amounts recognized in the consolidated statements of operations consist of:				
Gain on derivative financial instruments		**(2,626)**		(15,849)
Loss (gain) on foreign exchange		**16,845**		(3,289)
	$	**14,219**	$	(19,138)

25. 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 Liberty Power Group accounts receivable to be significant as over 90% of revenue from power generation is earned from large utility customers having a credit rating of BBB or better, and revenue is generally invoiced and collected within 45 days.

The remaining revenue is primarily earned by the Liberty Utilities Group which consists of water and wastewater, electric and gas utilities in the United States. In this regard, the credit risk related to the Liberty Utilities Group accounts receivable balances of U.S. $204,380 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 state regulators of the Liberty Utilities Group allow for a reasonable bad debt expense to be incorporated in the rates and therefore recovered from rate payers.

As of December 31, 2017, the Company's maximum exposure to credit risk for these financial instruments was as follows:

	December 31, 2017	
	Canadian $	US $
Cash and cash equivalents and restricted cash	$ 26,259	$ 38,491
Accounts receivable	14,468	238,637
Allowance for doubtful accounts	—	(5,555)
Notes receivable	37,710	3,318
	$ 78,437	$ 274,891

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, 2017, in addition to cash on hand of $54,550 the Company had $1,145,859 available to be drawn on its senior debt facilities. Each of the Company's revolving credit facilities contain covenants which may limit amounts available to be drawn.

25. 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	$ 279,724	$ 570,132	$ 644,969	$ 2,331,327	$ 3,826,152
Convertible Debentures	—	—	—	1,218	1,218
Advances in aid of construction	1,502	—	—	77,134	78,636
Interest on long-term debt	172,659	307,463	250,824	1,275,184	2,006,130
Purchase obligations	501,867	—	—	—	501,867
Environmental obligation	7,765	18,858	5,373	39,877	71,873
Derivative financial instruments:					
Cross-currency swap	4,386	8,077	64,726	(5,166)	72,023
Interest rate swaps	10,613	—	—	—	10,613
Currency forward	432	—	—	—	432
Energy derivative and commodity contracts	2,290	1,035	—	97	3,422
Other obligations	44,969	—	—	110,267	155,236
Total obligations	$ 1,026,207	$ 905,565	$ 965,892	$ 3,829,938	$ 6,727,602

26. Comparative figures

Certain of the comparative figures have been reclassified to conform to the financial statement presentation adopted in the current year.

Exhibit 99.3

Management Discussion & Analysis

(All monetary amounts are in thousands of Canadian dollars, except per share amounts or where otherwise noted.)

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, 2017. This Management Discussion & Analysis ("MD&A") should be read in conjunction with APUC's consolidated financial statements for the years ended December 31, 2017 and 2016. This material is available on SEDAR at www.sedar.com 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.

Unless otherwise indicated, financial information provided for the years ended December 31, 2017 and 2016 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.

This MD&A is based on information available to management as of March 7, 2018.

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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 statements" or "forward-looking information" within the meaning of applicable securities legislation (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 are not limited to, statements relating to: expected future growth and results of operations; liquidity, capital resources and operational requirements; rate cases, 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; ongoing and planned acquisitions, projects and initiatives, including expectations regarding costs, financing, results and completion dates; 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 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; contractual obligations and other commercial commitments; environmental liabilities; dividends to shareholders; 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 disruptions or liability due to natural disasters 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; 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; 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 best interests; 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 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.

Adjusted EBITDA

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 and gain or loss on foreign exchange, earnings or loss from discontinued operations 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.

Adjusted Net Earnings

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, and other typically non-recurring items as these are not reflective of the performance of the underlying business of APUC. For 2017, the one-time impact of the revaluation of U.S. non-regulated net deferred income tax assets as a result of the U.S. federal corporate income tax rate reduction from 35% to 21% enacted in December 2017 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. It is not intended to be representative of net earnings or loss determined in accordance with U.S. GAAP, which 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. It is not intended to be representative of cash flows from operating activities as determined in accordance with GAAP, which 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, and gain or loss on foreign exchange, earnings or loss from discontinued operations 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 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's current quarterly dividend to shareholders is U.S. $0.1165 per common share or U.S. $0.4660 per common share per annum. Based on exchange rates as at February 28, 2018, the quarterly dividend is equivalent to Cdn $0.1492 per common share or Cdn $0.5969 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 cash available for distribution and earnings together with an assessment of the growth prospects available to APUC. APUC strives to achieve its results in the context of a moderate risk profile consistent with top-quartile North American power and utility operations.

APUC's operations are organized across two primary North American business units consisting of: the Liberty Power Group, which owns and operates a diversified portfolio of non-regulated renewable and thermal electric generation assets; and the Liberty Utilities Group. which owns and operates a portfolio of regulated electric, natural gas, water distribution and wastewater collection utility systems, and transmission operations.

Liberty Power Group

The Liberty Power Group generates and sells electrical energy produced by its diverse portfolio of non-regulated renewable power generation and clean power generation facilities located across North America. The Liberty Power Group seeks to deliver continuing growth through development of new greenfield power generation projects and accretive acquisitions of additional electrical energy generation facilities.

The Liberty Power Group owns or has interests in hydroelectric, wind, solar, and thermal facilities with a combined generating capacity of approximately 120 MW, 1,050 MW, 40 MW, and 335 MW, respectively. Approximately 87% of the electrical output from the hydroelectric, wind, and solar generating facilities is sold pursuant to long term contractual arrangements which as of December 31, 2017 had a production-weighted average remaining contract life of approximately 15 years.

Liberty Utilities Group

The Liberty Utilities Group operates a diversified portfolio of regulated utility systems throughout the United States serving approximately 762,000 customers. The Liberty Utilities Group provides safe, high quality, and reliable services to its customers and seeks to deliver stable and predictable earnings to APUC. In addition to encouraging and supporting organic growth within its service territories, the Liberty Utilities Group seeks to deliver continued growth in earnings through accretive acquisition of additional utility systems.

The Liberty Utilities 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. The electric utility systems in total serve approximately 265,000 electric connections and operate a fleet of generation assets with a net capacity of 1,424 MW.

The Liberty Utilities Group's regulated natural gas distribution utility systems are located in the States of Georgia, Illinois, Iowa, Massachusetts, New Hampshire and Missouri serving approximately 337,000 natural gas connections.

The Liberty Utilities 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 160,000 connections.

Corporate Development

The Company is presently developing a portfolio of renewable power generation projects that, when constructed, will add approximately 361 MW of generation capacity from wind and solar powered generating facilities and, that when completed and on-line, will have a production-weighted average contract life of approximately 22 years.

2017 Major Highlights

Corporate Highlights

Strong Year of Operating Results

APUC recorded a strong twelve months of operating results relative to the same period last year.

	Twelve Months Ended December 31		
(all dollar amounts in $ millions except per share information)	2017	2016	Change
Net earnings attributable to shareholders	**$193.1**	$130.9	**48%**
Adjusted Net Earnings	**$292.1**	$161.6	**81%**
Adjusted EBITDA	**$883.4**	$476.9	**85%**
Net earnings per common share	**$0.48**	$0.44	**9%**
Adjusted Net Earnings per common share	**$0.74**	$0.57	**30%**

Declaration of Canadian Equivalent 2018 First Quarter Dividend of Cdn $0.1492 (U.S. $0.1165) per Common Share

On March 1, 2018, APUC announced that the Board of Directors of APUC declared a first quarter 2018 dividend of U.S. $0.1165 per common share payable on April 13, 2018 to shareholders of record on March 29, 2018. Based on the Bank of Canada exchange rate on the declaration date, the Canadian dollar equivalent for the first quarter 2018 dividend is set at Cdn $0.1492 per common share.

The previous four quarter equivalent Canadian dollar dividends per common share have been as follows:

	Q2 2017	Q3 2017	Q4 2017	Q1 2018	Total
U.S. dollar dividend	$0.1165	$0.1165	$0.1165	$0.1165	$0.4660
Canadian dollar equivalent	$0.1593	$0.1480	$0.1478	$0.1492	$0.6043

Investment in Joint Venture with Abengoa and Purchase of 25% Interest in Atlantica Yield plc

On November 1, 2017, APUC entered into an agreement to create a joint venture, Abengoa-Algonquin Global Energy Solutions ("AAGES"), with Seville, Spain-based Abengoa, S.A (MCE: ABG) ("Abengoa") to identify, develop, and construct clean energy and water infrastructure assets with a global focus. Concurrently with the creation of the AAGES joint venture, APUC entered into a definitive agreement to purchase from Abengoa a 25% equity interest in Atlantica Yield plc ("Atlantica") for a total purchase price of approximately U.S. $608 million, based on a price of U.S. $24.25 per ordinary share of Atlantica, plus a contingent payment of up to U.S. $0.60 per share payable two years after closing, subject to certain conditions. The transaction is expected to close sometime in the first quarter of 2018.

Completion of The Empire District Electric Company Acquisition and Financing

On January 1, 2017, APUC's wholly-owned regulated utility business successfully completed its acquisition of The Empire District Electric Company ("Empire") for an aggregate purchase price of approximately U.S. $2.414 billion including the assumption of approximately U.S. $0.9 billion of debt ("Empire Acquisition").

Empire is a Joplin, Missouri-based vertically integrated, regulated electric, gas and water utility with approximately 1.4 GW of generating capacity serving approximately 221,000 customers in Missouri, Kansas, Oklahoma, and Arkansas.

$1.15 Billion Bought Deal Offering of Convertible Unsecured Subordinated Debentures Represented by Instalment Receipts

In the first quarter of 2016, in connection with the Empire Acquisition, APUC and its direct wholly-owned subsidiary, Liberty Utilities (Canada) Corp., entered into an agreement with a syndicate of underwriters under which the underwriters agreed to buy, on a bought deal basis, $1.15 billion aggregate principal amount of 5.00% convertible unsecured subordinated debentures ("Debentures") of APUC (the "Debenture Offering").

Following the closing of the Empire Acquisition, the final instalment date was established as February 2, 2017, at which time APUC received the final instalment payment. The proceeds were used to repay a portion of APUC's bank facility drawn at closing of the Empire Acquisition ("Acquisition Facility"). As at March 6, 2018, approximately 99.9% of the Debentures have been converted into common shares of APUC, with APUC issuing approximately 108,384,716 common shares as a result of the conversion.

U.S. $750 Million Private Placement Offering

On March 24, 2017, the Liberty Utilities Group's financing entity issued U.S. $750 million of senior unsecured notes on a private placement basis to 29 institutional investors in the U.S. and Canada. The notes are of varying maturities from 3 to 30 years with a weighted average life of approximately 15 years and an effective interest rate of 3.6% (inclusive of interest rate hedges).

Corporate Financings Completed:

$576 Million Bought Deal Offering of Common Shares

On November 10, 2017, APUC announced that it closed a bought deal offering announced on November 1, 2017, including the exercise in full of the underwriters' over-allotment option. As a result, a total of 43,470,000 common shares of APUC were sold at a price of $13.25 per share for gross proceeds of approximately $576.0 million.

U.S. Tax Reform

On December 22, 2017, the Tax Cuts and Jobs Act ("U.S. Tax Reform") was signed into law in the U.S., which, amongst other significant changes, reduced the U.S. federal corporate tax rate from 35% to 21%.

As a result of U.S. Tax Reform, the Company is required to revalue its U.S. deferred income tax assets and liabilities based on the new tax rate. This revaluation resulted in a one time non-cash accounting charge of $22.4 million to be recorded in the Company's consolidated statement of operations for the quarter and year ended December 31, 2017.

The Company expects that the effects of U.S. Tax Reform in 2018 will be neutral to slightly positive to EPS and approximately 2%-3% negative to 2018 EBITDA, which is within the planning parameters that APUC establishes for normal variability in its business cycle from wind, hydrology and weather.

The Company expects its effective tax rate in 2018 on its consolidated worldwide net income to be below 20%.

Additional detail on U.S. Tax Reform can be found later in this document under Corporate and Other expenses.

Change to U.S. Dollar Reporting

Effective the first quarter of 2018, APUC's interim and annual consolidated financial statements will be reported in U.S. dollars.

Over 90% of APUC's consolidated revenue, EBITDA and assets are derived from operations in the United States. In addition, APUC's dividend is denominated in U.S. dollars and the Company's common shares are listed on the New York Stock Exchange. The Company believes that the change in reporting to U.S. dollars will provide improved information to investors and allow for better assessment of its results without the effects of the change in currency on 90% of its operations.

Liberty Power Group Highlights

Completion of the Deerfield Wind Project

On February 21, 2017, the Deerfield Wind Facility achieved commercial operations ("COD"). The project consists of a 150 MW wind generating facility located in central Michigan. On May 10, 2017, tax equity financing of approximately U.S. $166.6 million was completed. The Deerfield Wind Facility is the Liberty Power Group's tenth wind generating facility and consists of 44 Vestas V110-2.0 wind turbines and 28 Vestas V110-2.2 turbines and is expected to generate 555.2 GW-hrs annually. The project has a 20 year Power Purchase Agreement ("PPA") with a local electric distribution utility serving approximately 260,000 customers in Michigan.

Completion of the Bakersfield II Solar Project

On January 11, 2017, the Liberty Power Group achieved COD on the 10 MWac solar generating facility located in Kern County, California (the "Bakersfield II Solar Facility"). On February 28, 2017, tax equity financing of approximately U.S. $12.3 million was completed. The Bakersfield II Solar Facility is the Liberty Power Group's third solar generating facility and is comprised of approximately 38,640 solar panels located on 64 acres of land. The project is expected to generate 24.2 GW-hrs of energy annually. The project has a 20 year PPA with a large investment grade electric utility in California.

Issuance of $300 million Senior Unsecured Debentures

On January 17, 2017, the Liberty Power Group issued $300.0 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 $99.929 per $100.00 principal amount. Concurrent with the offering, the Liberty Power Group entered into a cross currency swap, coterminous with the debentures, to economically convert the Canadian dollar denominated offering into U.S. dollars.

The net proceeds were used to partially finance the Odell Wind, Deerfield Wind and Bakersfield II Solar projects.

Liberty Utilities Group Highlights

Successful Rate Case Outcomes

A core strategy of the Liberty Utilities Group is to ensure an appropriate return is earned on the rate base at its various utility systems. During 2017, the Liberty Utilities Group successfully completed several rate cases representing a cumulative annualized revenue increase of approximately U.S. $20.4 million. The Liberty Utilities Group has pending rate case filings in progress that are expected to be completed in 2018 that if successful will represent an increase in rates in the amount of U.S. $44.9 million.

Application to Develop up to 800 MW of Wind in the Midwest

On October 31, 2017, Empire announced a proposed plan to phase out its Asbury coal generation facility and expand its wind resources with the development of up to an additional 800 MW of strategically located wind generation in or near its service territory by the end of 2020. The plan projects cost savings for customers of U.S. $172.0 - U.S. $325.0 million over a twenty-year period. Empire filed a request for approval of the wind expansion initiative with regulators in Missouri, Kansas, Oklahoma, and Arkansas, and the project is subject to their respective review. Orders from the various jurisdictions are anticipated by June 2018.

Granite Bridge Project

On December 4, 2017, the Liberty Utilities Group announced plans for the development of a new infrastructure project designed to bring additional natural gas supply to New Hampshire's residents and businesses. The project, called Granite Bridge, would bring natural gas from existing infrastructure located in New Hampshire's Seacoast region to the central part of the state through an underground pipeline. The proposed Granite Bridge project is estimated to cost between U.S. $320.0 million and U.S. $360 million and would connect the existing Portland Natural Gas Transmission System and Maritimes and Northeast Pipeline facilities in Stratham with the existing Tennessee Gas Pipeline facilities in Manchester. The Granite Bridge project also includes a proposed Liquefied Natural Gas storage facility capable of storing up to two billion cubic feet of natural gas. The final project will be subject to approval from regulatory authorities.

Acquisition of the St. Lawrence Gas Company, Inc.

On August 31, 2017, the Company entered into a definitive agreement to acquire St. Lawrence Gas Company, Inc. ("SLG"). SLG is a rate-regulated natural gas distribution utility serving approximately 16,000 customers in northern New York State. The total purchase price for the transaction is U.S. $70.0 million, less total third-party debt of SLG outstanding at closing, and subject to customary working capital adjustments. Closing of the transaction remains subject to regulatory approval and other closing conditions and is expected to occur in late 2018 or early 2019.

Acquisition of the Perris Water Distribution System

On August 10, 2017, the Company's board approved the acquisition of two water distribution systems serving approximately 4,000 customers in the City of Perris, California. The anticipated purchase price of U.S. $11.5 million is expected to be established as rate base during the regulatory approval process. Liberty Utilities was the successful bidder in the city's request for proposal process and in July 2017 the Perris City council voted to approve the sale to Liberty Utilities. The City of Perris residents voted to approve the sale on November 7, 2017. Liberty Utilities expects to file the advice letter to acquire the water utility with the California Public Utility Commission ("CPUC") in Q1 2018, with approval expected in late 2018.

Completion of the Luning Solar Facility

On February 15, 2017, the Liberty Utilities Group acquired control of a 50 MWac solar generating facility located in Mineral County, Nevada for approximately U.S. $110.9 million. The facility is comprised of approximately 204,784 solar panels located on 584 acres of land. The facility is expected to generate 144.6 GW-hrs of energy annually. On February 17, 2017, tax equity financing of approximately U.S. $39.0 million was completed. The net capital cost of the facility 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.

2017 Fourth Quarter Results From Operations

Key Financial Information

(all dollar amounts in $ millions except per share information)	Three Months Ended December 31 2017	2016
Revenue	**$ 523.4**	$ 310.2
Net earnings attributable to shareholders	**60.0**	46.3
Cash provided by operating activities	**169.8**	121.9
Adjusted Net Earnings[1]	**85.9**	51.4
Adjusted EBITDA[1]	**233.4**	138.3
Adjusted Funds from Operations[1]	**159.1**	96.4
Dividends declared to common shareholders	**64.0**	39.2
Weighted average number of common shares outstanding	**412,632,308**	273,952,963
Per share		
Basic net earnings	**$ 0.14**	$ 0.16
Diluted net earnings	**$ 0.14**	$ 0.16
Adjusted Net Earnings[1,2]	**$ 0.20**	$ 0.18
Dividends declared to common shareholders	**$ 0.15**	$ 0.14

[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, 2017, APUC experienced an average U.S. exchange rate of approximately 1.2715 as compared to 1.3343 in the same period in 2016. As such, any quarter over quarter variance in revenue or expenses, in local currency, at any of APUC's U.S. 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, 2017, APUC reported total revenue of $523.4 million as compared to $310.2 million during the same period in 2016, an increase of $213.2 million. The major factors resulting in the increase in APUC revenue in the three months ended December 31, 2017 as compared to the corresponding period in 2016 are set out as follows:

(all dollar amounts in $ millions)		Three Months Ended December 31
Comparative Prior Period Revenue	**$**	**310.2**
LIBERTY POWER GROUP		
Existing Facilities		
Hydro: Decrease due to lower pricing in Hydro Quebec PPA renewals and a decline in pricing in the Western Region, partially offset by higher overall production.		(0.4)
Wind Canada: Increase primarily due to higher production and annual rate increases in PPAs.		1.9
Wind U.S.: Increase primarily due to higher overall production.		1.3
Solar Canada: Increase primarily due to higher production.		0.1
Solar U.S.: Increase primarily due to higher production.		0.1
Thermal: Increase is primarily due to higher overall production as well as a new capacity-based contract at the Sanger Thermal Facility.		2.9
Other:		(0.5)
		5.4
New Facilities		
Wind US: Acquisition of Deerfield Wind Facility in March 2017.		9.5
Solar US: Bakersfield II Solar Facility was placed in service in December 2016.		0.3
		9.8
Foreign Exchange		**(2.3)**
LIBERTY UTILITIES GROUP		
Existing Facilities		
Electricity: Decrease primarily due to retroactive recognition of 12 months of revenue in Q4 of 2016 arising from the 2016 rate case at the Calpeco Electric System.		(7.2)
Gas: Increase primarily due to higher demand and pass through gas costs at the New England and Midstates Gas Systems from increased heating degree days, partially offset by lower pass through gas costs at the EnergyNorth Gas System.		14.5
Water: Decrease primarily due to divestiture of Mountain Water System from condemnation proceedings on June 22, 2017.		(2.9)
Other: Decrease primarily due to lower contracted services.		(1.8)
		2.6
New Facilities		
Electricity: Acquisition of both Empire's electric distribution system ($180.8 million) on January 1, 2017 and the Luning Solar Facility ($3.6 million) on February 15, 2017.		184.4
Gas: Acquisition of Empire's gas distribution system on January 1, 2017.		14.6
Water: Acquisition of Empire's water distribution system on January 1, 2017.		0.6
Other: Acquisition of Empire's fiber optic operations on January 1, 2017.		2.0
		201.6
Rate Cases		
Electricity: Implementation of new rates at the Granite State Electric System.		1.0
Gas: Implementation of new rates at the EnergyNorth, Midstates, New England, and Peach State Gas Systems.		4.1
Water: Implementation of new rates at the Park Water System.		2.0
		7.1
Foreign Exchange		**(11.0)**
Current Period Revenue	**$**	**523.4**

A more detailed discussion of these factors is presented within the business unit analysis.

For the three months ended December 31, 2017, net earnings attributable to shareholders totaled $60.0 million as compared to $46.3 million during the same period in 2016, an increase of $13.7 million or 29.6%. The increase was due to a $101.6 million increase in earnings from operating facilities and a $1.1 million decrease in acquisition related costs. These items were partially offset by a $5.6 million increase in administration charges, $35.4 million increase in depreciation and amortization expenses, $0.3 million decrease in foreign exchange gain, $3.7 million increase in interest expense, $0.6 million decrease in interest, dividend, equity and other income, $3.3 million decrease in other gains, $2.3 million decrease in gains on long lived assets, $8.9 million decrease in gains from derivative instruments, $2.4 million decrease in net effect of non-controlling interests, and a $26.5 million increase in income tax expense (tax explanations are discussed in *APUC: Corporate and Other Expenses)* as compared to the same period in 2016.

During the three months ended December 31, 2017, cash provided by operating activities totaled $169.8 million as compared to cash provided by operating activities of $121.9 million during the same period in 2016. During the three months ended December 31, 2017, Adjusted Funds from Operations totaled $159.1 million compared to Adjusted Funds from Operations of $96.4 million during the same period in 2016. The change in Adjusted Funds from Operations in the three months ended December 31, 2017 is primarily due to increased earnings from operations (including Empire) as compared to the same period in 2016.

During the three months ended December 31, 2017, Adjusted EBITDA totaled $233.4 million as compared to $138.3 million during the same period in 2016, an increase of $95.1 million or 68.8%. 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*).

2017 Annual Results From Operations

Key Financial Information

(all dollar amounts in $ millions except per share information)	Twelve Months Ended December 31		
	2017	**2016**	**2015**
Revenue	**$ 1,977.8**	$ 1,096.0	$ 1,027.9
Net earnings attributable to shareholders from continuing operations	**193.1**	130.9	118.5
Net earnings attributable to shareholders	**193.1**	130.9	117.5
Cash provided by operating activities	**457.8**	287.9	261.9
Adjusted Net Earnings[1]	**292.1**	161.6	121.5
Adjusted EBITDA[1]	**883.4**	476.9	375.4
Adjusted Funds from Operations[1]	**614.5**	356.4	287.4
Dividends declared to common shareholders	**242.5**	149.2	124.8
Weighted average number of common shares outstanding	**382,323,434**	271,832,430	253,172,088
Per share			
Basic net earnings from continuing operations	**$ 0.48**	$ 0.44	$ 0.43
Basic net earnings	**$ 0.48**	$ 0.44	$ 0.42
Diluted net earnings	**$ 0.47**	$ 0.44	$ 0.42
Adjusted Net Earnings[1,2]	**$ 0.74**	$ 0.57	$ 0.46
Dividends declared to common shareholders	**$ 0.61**	$ 0.55	$ 0.49
Total assets	**10,533.6**	8,249.5	4,991.7
Long term debt[3]	**3,864.5**	4,272.0	1,486.8

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, 2017 , APUC experienced an average U.S. exchange rate of approximately 1.2980 as compared to 1.3253 in the same period in 2016. As such, any year-over-year variance in revenue or expenses, in local currency, at any of APUC's U.S. 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, 2017 , APUC reported total revenue of $1,977.8 million as compared to $1,096.0 million during the same period in 2016, an increase of $881.8 million or 80.5%. The major factors resulting in the increase in APUC revenue for the twelve months ended December 31, 2017 as compared to the corresponding period in 2016 are set out as follows:

(all dollar amounts in $ millions)		Twelve Months Ended December 31
Comparative Prior Period Revenue	**$**	**1,096.0**
LIBERTY POWER GROUP		
Existing Facilities		
Hydro: Decrease primarily due to prior year recognition of a Global Adjustment payment from the Ontario IESO, and lower pricing in Hydro Quebec PPA renewals, coupled with lower production in the Maritime and Western Regions.		(7.5)
Wind Canada: Increase primarily due to higher production and annual PPA rate increases.		2.2
Wind U.S.: Decrease primarily due to lower REC pricing, partially offset by higher production at Minonk and Shady Oaks Wind Facilities.		(0.8)
Solar Canada: Decrease primarily due to lower production, largely in the second quarter of 2017.		(0.6)
Solar U.S.: Decrease primarily due to business interruption insurance payments received in the prior year.		(0.4)
Thermal: Increase primarily due to higher pass through fuel costs at the Windsor Locks Thermal Facility, as well as a new capacity-based contract at the Sanger Thermal Facility.		4.2
Other: Decrease primarily due to the shutdown of the hydro mulch business at the Sanger Thermal Facility.		(1.9)
		(4.8)
New Facilities		
Wind U.S.: Acquisition of Odell (September 2016) and Deerfield (March 2017) Wind Facilities.		40.8
Solar U.S.: Bakersfield II Solar Facility was placed in service in December 2016.		2.1
		42.9
Foreign Exchange		**(3.6)**
LIBERTY UTILITIES GROUP		
Existing Facilities		
Electricity: Decrease primarily due to lower pass through energy costs at the Calpeco Electric System.		(8.3)
Gas: Increase primarily due to higher consumption at the EnergyNorth and New England Gas Systems due to higher heating degree days combined with higher pass through gas costs at the Peach State Gas System.		38.0
Water: Decrease primarily due divestiture of Mountain Water System from condemnation proceedings on June 22, 2017.		(6.5)
Other: Decrease primarily due to lower contracted services.		(6.0)
		17.2
New Facilities		
Electricity: Acquisition of both Empire's electric distribution system ($754.6 million) on January 1, 2017 and the Luning Solar Facility ($14.7 million) on February 15, 2017.		769.3
Gas: Acquisition of Empire's gas distribution system on January 1, 2017.		46.9
Water: Acquisition of Empire's water distribution system on January 1, 2017.		2.7
Other: Acquisition of Empire's fiber optic operations on January 1, 2017.		8.1
		827.0
Rate Cases		
Electricity: Implementation of new rates at the Granite State Electric System.		5.2
Gas: Implementation of new rates at the EnergyNorth, Midstates, New England, and Peach State Gas Systems.		12.5
Water: Implementation of new rates at the Park Water, Bella Vista, Rio Rico and Black Mountain Water and Wastewater Systems.		6.1
		23.8
Foreign Exchange		**(20.7)**
Current Period Revenue	**$**	**1,977.8**

A more detailed discussion of these factors is presented within the business unit analysis.

For the twelve months ended December 31, 2017 , net earnings attributable to shareholders totaled $193.1 million as compared to $130.9 million during the same period in 2016, an increase of $62.2 million. The increase was due to a $401.4 million increase in earnings from operating facilities, $1.4 million increase in interest, dividend, equity and other income, and $23.6 million increase in net effect of non-controlling interests. These items were partially offset by an $18.2 million increase in administration charges, $139.5 million increase in depreciation and amortization expenses, $0.8 million decrease in foreign exchange gains, $71.0 million increase in interest expense, $11.8 million decrease in other gains, $50.8 million increase in acquisition costs, $0.8 million decrease in gain on long lived assets, $13.2 million decrease on gains from derivative instruments and $58.1 million increase in income tax expense (tax explanations are discussed in *APUC: Corporate and Other Expenses*) as compared to the same period in 2016.

During the twelve months ended December 31, 2017 , cash provided by operating activities totaled $457.8 million as compared to cash provided by operating activities of $287.9 million during the same period in 2016. During the twelve months ended December 31, 2017 , Adjusted Funds from Operations, a non-GAAP measure, totaled $614.5 million as compared to Adjusted Funds from Operations of $356.4 million the same period in 2016, an increase of $258.1 million.

Adjusted EBITDA in the twelve months ended December 31, 2017 totaled $883.4 million as compared to $476.9 million during the same period in 2016, an increase of $406.5 million or 85.2%. 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*).

2017 Adjusted EBITDA Summary

Adjusted EBITDA (see *Non-GAAP Financial Measures*) for the three months ended December 31, 2017 totaled $233.4 million as compared to $138.3 million during the same period in 2016, an increase of $95.1 million or 68.8%. Adjusted EBITDA for the twelve months ended December 31, 2017 totaled $883.4 million as compared to $476.9 million during the same period in 2016, an increase of $406.5 million or 85.2%. 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 (all dollar amounts in $ millions)	Three Months Ended December 31		Twelve Months Ended December 31	
	2017	2016	2017	2016
Liberty Power Operating Profit	**$ 70.8**	$ 61.9	**$ 250.9**	$ 217.3
Liberty Utilities Group Operating Profit	**180.7**	85.9	**694.1**	300.5
Administrative Expenses	**(18.7)**	(13.1)	**(64.5)**	(46.3)
Other Income & Expenses	**0.6**	3.6	**2.9**	5.4
Total Algonquin Power & Utilities Adjusted EBITDA	**$ 233.4**	$ 138.3	**$ 883.4**	$ 476.9
Change in Adjusted EBITDA ($)	**$ 95.1**		**$ 406.5**	
Change in Adjusted EBITDA (%)	**68.8%**		**85.2%**	

Change in Adjusted EBITDA (all dollar amounts in $ millions)	Three Months Ended December 31, 2017			
	Power	Utilities	Corporate	Total
Prior period balances	**$ 61.9**	**$ 85.9**	**$ (9.5)**	**$ 138.3**
Existing Facilities	7.8	(5.6)	(3.0)	(0.8)
New Facilities	3.0	97.3	—	100.3
Rate Cases	—	7.1	—	7.1
Foreign Exchange Impact	(1.9)	(4.0)	—	(5.9)
Administrative Expenses	—	—	(5.6)	(5.6)
Total change during the period	**$ 8.9**	**$ 94.8**	**$ (8.6)**	**$ 95.1**
Current period balances	**$ 70.8**	**$ 180.7**	**$ (18.1)**	**$ 233.4**

Change in Adjusted EBITDA (all dollar amounts in $ millions)	Twelve Months Ended December 31, 2017			
	Power	Utilities	Corporate	Total
Prior period balances	**$ 217.3**	**$ 300.5**	**$ (40.9)**	**$ 476.9**
Existing Facilities	0.9	(4.5)	(2.6)	(6.2)
New Facilities	34.9	381.0	—	415.9
Rate Cases	—	23.8	—	23.8
Foreign Exchange Impact	(2.2)	(6.7)	—	(8.9)
Administration Expenses	—	—	(18.1)	(18.1)
Total change during the period	**$ 33.6**	**$ 393.6**	**$ (20.7)**	**$ 406.5**
Current period balances	**$ 250.9**	**$ 694.1**	**$ (61.6)**	**$ 883.4**

LIBERTY POWER GROUP

2017 Electricity Generation Performance

(Performance in GW-hrs sold)	Long Term Average Resource	Three Months Ended December 31 2017	2016	Long Term Average Resource	Twelve Months Ended December 31 2017	2016
Hydro Facilities:						
Maritime Region	**37.6**	**34.9**	21.9	**148.2**	**129.7**	144.1
Quebec Region	**72.6**	**67.5**	64.0	**273.3**	**270.6**	267.5
Ontario Region	**31.9**	**30.6**	28.6	**136.0**	**129.5**	126.8
Western Region	**12.6**	**10.5**	18.1	**65.0**	**59.6**	66.1
	154.7	**143.5**	132.6	**622.5**	**589.4**	604.5
Wind Facilities:						
St. Damase	**22.7**	**24.0**	20.4	**76.9**	**74.3**	74.4
St. Leon	**121.4**	**138.7**	130.8	**430.2**	**444.2**	417.3
Red Lily[1]	**24.1**	**29.2**	25.4	**88.5**	**91.6**	82.6
Morse	**30.5**	**33.1**	27.7	**108.8**	**106.4**	94.8
Sandy Ridge	**43.6**	**42.0**	51.8	**158.3**	**153.3**	155.8
Minonk	**189.8**	**203.5**	184.9	**673.7**	**673.7**	635.8
Senate	**140.0**	**126.6**	136.7	**520.4**	**492.8**	504.4
Shady Oaks	**100.5**	**108.7**	104.4	**355.6**	**365.5**	323.9
Odell[2]	**238.0**	**244.6**	211.2	**831.8**	**807.2**	297.7
Deerfield[3]	**160.0**	**164.3**	—	**472.6**	**449.3**	—
	1,070.6	**1,114.7**	893.3	**3,716.8**	**3,658.3**	2,586.7
Solar Facilities:						
Cornwall	**2.2**	**2.1**	1.9	**14.7**	**14.4**	15.6
Bakersfield I	**8.9**	**8.7**	7.4	**52.8**	**48.3**	45.9
Bakersfield II[4]	**4.1**	**4.0**	—	**24.4**	**22.2**	—
	15.2	**14.8**	**9.3**	**91.9**	**84.9**	**61.5**
Renewable Energy Performance	**1,240.5**	**1,273.0**	1,035.2	**4,431.2**	**4,332.6**	3,252.7
Thermal Facilities:						
Windsor Locks	**N/A[5]**	**31.8**	30.9	**N/A[5]**	**122.0**	131.0
Sanger	**N/A[5]**	**33.5**	28.8	**N/A[5]**	**86.0**	118.7
		65.3	59.7		**208.0**	249.7
Total Performance		**1,338.3**	1,094.9		**4,540.6**	3,502.4

[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] The Odell Wind Facility achieved COD on July 29, 2016 and was treated as an equity investment until September 15, 2016 at which time the Company acquired the remaining 50% ownership in the facility.

[3] The Deerfield Wind Facility achieved COD on February 21, 2017 and was treated as an equity investment until March 14, 2017 at which time the Company acquired the remaining 50% ownership in the facility. The long-term average resources ("LTAR") and production noted above represents all production from the date of COD.

[4] The Bakersfield II Solar Facility achieved COD on January 11, 2017 in accordance with the terms of the PPA. The LTAR and production noted above represents all production from the date of COD.

[5] Natural gas fired co-generation facility.

2017 Fourth Quarter Liberty Power Group Performance

For the three months ended December 31, 2017 , the Liberty Power Group generated 1,338.3 GW-hrs of electricity as compared to 1,094.9 GW-hrs during the same period of 2016.

For the three months ended December 31, 2017 , the hydro facilities generated 143.5 GW-hrs of electricity as compared to 132.6 GW-hrs produced in the same period in 2016, an increase of 8.2%. Electricity generated represented 92.8% of long-term average resources ("LTAR") as compared to 85.7% during the same period in 2016. During the quarter, all regions were below their respective LTAR.

For the three months ended December 31, 2017 , the wind facilities produced 1,114.7 GW-hrs of electricity as compared to 893.3 GW-hrs produced in the same period in 2016, an increase of 24.8%. The higher generation was primarily due to the addition of the Deerfield Wind Facility which achieved COD on February 21, 2017. This increase was partially offset by lower production at the Senate and Sandy Ridge Wind Facilities. During the three months ended December 31, 2017 , the wind facilities (excluding the Deerfield Wind Facility) generated electricity equal to 104.3% of LTAR as compared to 98.0% during the same period in 2016.

For the three months ended December 31, 2017 , the solar facilities generated 14.8 GW-hrs of electricity as compared to 9.3 GW-hrs of electricity in the same period in 2016, an increase of 59.1%. The increase in production is primarily due to the addition of the Bakersfield II Solar Facility which achieved COD on January 11, 2017. The solar facilities (excluding Bakersfield II) production was 2.7% below its LTAR as compared to 16.2% below in the same period in 2016.

For the three months ended December 31, 2017 , the thermal facilities generated 65.3 GW-hrs of electricity as compared to 59.7 GW-hrs of electricity during the same period in 2016. During the same period, the Windsor Locks Thermal Facility generated 136.9 billion lbs of steam as compared to 129.3 billion lbs of steam during the same period in 2016.

2017 **Annual Liberty Power Group** Performance

For the twelve months ended December 31, 2017 , the Liberty Power Group generated 4,540.6 GW-hrs of electricity as compared to 3,502.4 GW-hrs during the same period of 2016.

For the twelve months ended December 31, 2017 , the hydro facilities generated 589.4 GW-hrs of electricity as compared to 604.5 GW-hrs produced in the same period in 2016, a decrease of 2.5%. Electricity generated represented 94.7% of long-term projected average resources as compared to 97.1% during the same period in 2016. The decrease is primarily due to reduced hydrology in the Maritime and Western Region's partially offset by increased generation in the Quebec and Ontario Regions.

For the twelve months ended December 31, 2017 , the wind facilities produced 3,658.3 GW-hrs of electricity as compared to 2,586.7 GW-hrs produced in the same period in 2016, an increase of 41.4%. During the twelve months ended December 31, 2017 , the wind facilities generated electricity equal to 98.4% of LTAR as compared to 93.9% during the same period in 2016. The increase in production was primarily due to higher production at the Shady Oaks, Minonk and St. Leon Wind Facilities as well as the incremental electricity generated at the Deerfield and Odell Wind Facilities which achieved COD on February 21, 2017 and July 29, 2016, respectively.

For the twelve months ended December 31, 2017 , the solar facilities generated 84.9 GW-hrs of electricity as compared to 61.5 GW-hrs of electricity produced in the same period in 2016, an increase of 38.0%. The increase in production is primarily due to the addition of the Bakersfield II Solar Facility which achieved COD on January 11, 2017. The solar facilities (excluding Bakersfield II) production was 7.1% below its LTAR as compared to 8.9% below in the same period in 2016.

For the twelve months ended December 31, 2017 , the thermal facilities generated 208.0 GW-hrs of electricity as compared to 249.7 GW-hrs of electricity during the same period in 2016. During the same period, the Windsor Locks Thermal Facility generated 559.1 billion lbs of steam as compared to 552.5 billion lbs of steam during the same period in 2016.

2017 Liberty Power Group Operating Results

(all dollar amounts in $ millions)	Three Months Ended December 31		Twelve Months Ended December 31	
	2017	2016	2017	2016
Revenue[1]				
Hydro	**$ 14.0**	$ 14.6	**$ 58.2**	$ 66.5
Wind	**54.0**	42.6	**171.6**	128.2
Solar	**2.0**	1.6	**14.0**	12.9
Thermal	**11.1**	8.2	**38.8**	35.5
Total Revenue	**$ 81.1**	$ 67.0	**$ 282.6**	$ 243.1
Less:				
Cost of Sales - Energy[2]	**(1.9)**	(1.8)	**(6.5)**	(5.8)
Cost of Sales - Thermal	**(5.8)**	(4.4)	**(18.9)**	(15.5)
Realized gain/(loss) on hedges[3]	**—**	—	**(0.7)**	(1.0)
Net Energy Sales	**$ 73.4**	$ 60.8	**$ 256.5**	$ 220.8
Renewable Energy Credits ("REC")[4]	**5.5**	6.3	**17.1**	20.2
Other Revenue	**0.1**	0.5	**0.5**	2.4
Total Net Revenue	**$ 79.0**	$ 67.6	**$ 274.1**	$ 243.4
Expenses & Other Income				
Operating expenses	**(21.9)**	(20.2)	**(86.7)**	(72.3)
Interest, dividend, equity and other income	**1.1**	0.9	**3.7**	5.2
HLBV income[5]	**12.6**	13.6	**59.8**	41.0
Divisional Operating Profit[6,7]	**$ 70.8**	$ 61.9	**$ 250.9**	$ 217.3

1 While most of the Liberty Power Group's PPAs include annual rate increases, 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 financial statements *note 25(b)(iv)*.

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 of electricity was generated from an eligible energy source.

5 HLBV income represents the value of net tax attributes earned by the Liberty Power Group in the period primarily from electricity generated by certain of its U.S. wind power and U.S. solar generation facilities.

6 Certain prior year items have been reclassified to conform to current year presentation.

7 See *Non-GAAP Financial Measures*.

2017 Fourth Quarter Operating Results

For the three months ended December 31, 2017 , the Liberty Power Group's facilities generated $70.8 million of operating profit as compared to $61.9 million during the same period in 2016, which represents an increase of $8.9 million or 14.4%, 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	**$**	**61.9**
Existing Facilities		
Hydro: Decrease due to lower pricing in Hydro Quebec PPA renewals and a decline in pricing in the Western Region, partially offset by higher overall production.		(0.6)
Wind Canada: Increase primarily due to higher production and annual PPA rate increases.		1.9
Wind U.S.: Increase primarily due to higher production and HLBV income at the Minonk and Odell Wind Facilities.		4.7
Solar Canada: Increase primarily due to higher production.		0.1
Solar U.S.: Increase primarily due to higher production.		0.3
Thermal: Increase primarily due to higher overall production as well as a new capacity-based contract at the Sanger Thermal Facility.		1.3
Other:		0.1
		7.8
New Facilities		
Wind U.S.: Acquisition of Deerfield Wind Facility in March 2017.		2.2
Solar U.S.: Bakersfield II was placed in service in December 2016.		0.8
		3.0
Foreign Exchange		**(1.9)**
Current Period Divisional Operating Profit	**$**	**70.8**

2017 Annual Operating Results

For the twelve months ended December 31, 2017 , the Liberty Power Group's facilities generated $250.9 million of operating profit as compared to $217.3 million during the same period in 2016, which represents an increase of $33.6 million or 15.5%, 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	**$**	**217.3**
Existing Facilities		
Hydro: Decrease primarily due to prior year recognition of a Global Adjustment payment from the Ontario IESO, and pricing settlement in the Quebec Region, coupled with lower production in the Maritime and Western Regions.		(8.2)
Wind Canada: Increase primarily due to higher production and annual rate increases.		1.8
Wind U.S.: Increase primarily due to higher HLBV income and higher production at the Minonk and Shady Oaks Wind Facilities.		6.7
Solar Canada: Decrease primarily due to lower production, largely in the second quarter of 2017.		(0.2)
Solar U.S.: Decrease primarily due to business interruption insurance payments received in the prior year.		(0.4)
Thermal: Increase primarily due to higher pass through fuel costs at to the Windsor Locks Thermal Facility, as well as a new capacity-based contract at the Sanger Thermal Facility.		0.4
Other:		0.8
		0.9
New Facilities		
Wind U.S.: Acquisition of Odell (September 2016) and Deerfield (March 2017) Wind Facilities.		31.3
Solar U.S.: Bakersfield II was placed in service in December 2016.		3.6
		34.9
Foreign Exchange		**(2.2)**
Current Period Divisional Operating Profit	**$**	**250.9**

LIBERTY UTILITIES GROUP

The Liberty Utilities Group operates rate-regulated utilities that provide distribution services to approximately 762,000 connections in the natural gas, electric, water and wastewater sectors. On January 1, 2017, the Liberty Utilities Group completed the acquisition of Empire. Empire is a vertically-integrated utility providing electric, natural gas and water service serving approximately 221,000 customers in Missouri, Kansas, Oklahoma, and Arkansas. The Liberty Utilities Group's strategy is to grow its business organically and through business development activities while using prudent acquisition criteria. The Liberty Utilities 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

	As at December 31			
	2017		2016	
(all dollar amounts in U.S. $ millions)	Assets	Total Connections[1]	Assets	Total Connections[1]
Electricity	**$ 2,479.9**	**265,000**	$ 378.4	94,000
Natural Gas	**996.1**	**337,000**	845.9	293,000
Water and Wastewater	**462.6**	**160,000**	516.4	178,000
Total	**$ 3,938.6**	**762,000**	$ 1,740.7	565,000
Accumulated Deferred Income Taxes Liability	**$ 392.8**		$ 194.7	

[1] Total Connections represents the sum of all active and vacant connections.

The Liberty Utilities 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 265,000 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 337,000 connections located in the states of New Hampshire, Illinois, Iowa, Missouri, Georgia, and Massachusetts.

The water and wastewater distribution systems are comprised of regulated water distribution and wastewater collection utility systems and serve approximately 160,000 connections located in the states of Arkansas, Arizona, California, Illinois, Missouri and Texas.

2017 Fourth Quarter Usage Results

Electric Distribution Systems

	Three Months Ended December 31	
	2017	2016
Average Active Electric Connections For The Period		
Residential	224,400	80,600
Commercial and industrial	39,200	12,500
Total Average Active Electric Connections For The Period	**263,600**	**93,100**
Customer Usage (GW-hrs)		
Residential	571.7	142.5
Commercial and industrial	882.3	225.0
Total Customer Usage (GW-hrs)	**1,454.0**	**367.5**

For the three months ended December 31, 2017 , the electric distribution systems' usage totaled 1,454.0 GW-hrs as compared to 367.5 GW-hrs for the same period in 2016, an increase of 1,086.5 GW-hrs or 295.6%. The addition of Empire accounted for 1,091.6 GW-hrs of the increase. Excluding Empire, usage was 5.1 GW-hrs, or 1.4%, lower due to lower commercial usage at the Calpeco Electric System.

Natural Gas Distribution Systems

	Three Months Ended December 31	
	2017	2016
Average Active Natural Gas Connections For The Period		
Residential	286,700	248,100
Commercial and industrial	31,700	26,600
Total Average Active Natural Gas Connections For The Period	**318,400**	**274,700**
Customer Usage (MMBTU)		
Residential	5,196,000	3,737,000
Commercial and industrial	4,282,000	3,446,000
Total Customer Usage (MMBTU)	**9,478,000**	**7,183,000**

For the three months ended December 31, 2017, usage at the natural gas distribution systems totaled 9,478,000 MMBTU as compared to 7,183,000 MMBTU during the same period in 2016, an increase of 2,295,000 MMBTU, or 32.0%. The addition of Empire accounted for 1,069,000 MMBTU of the increase. Excluding Empire, usage was 1,226,000 MMBTU, or 17.1%, higher primarily due to increased consumption at the Midstates and Peach State Gas Systems.

Water and Wastewater Distribution Systems

	Three Months Ended December 31	
	2017	2016
Average Active Connections For The Period		
Wastewater connections	41,400	41,100
Water distribution connections	111,800	129,400
Total Average Active Connections For The Period	**153,200**	**170,500**
Gallons Provided		
Wastewater treated (millions of gallons)	555	542
Water provided (millions of gallons)	3,909	4,113
Total Gallons Provided	**4,464**	**4,655**

During the three months ended December 31, 2017, the water and wastewater distribution systems provided approximately 3,909 million gallons of water to its customers and treated approximately 555 million gallons of wastewater as compared to 4,113 million gallons of water provided and 542 million gallons of wastewater treated during the same period in 2016. The decrease in the gallons of water provided to customers can be attributed to the disposition of the Mountain Water System in Montana. Excluding the Mountain Water System, the water provided to customers was approximately 289 million gallons, or 7%, higher.

2017 Fourth Quarter Operating Results

	Three Months Ended December 31			
	2017 U.S. $ (millions)	2016 U.S. $ (millions)	2017 Can $ (millions)	2016 Can $ (millions)
Revenue				
Utility electricity sales and distribution	**$ 187.0**	$ 46.9	**$ 237.8**	$ 62.5
Less: cost of sales – electricity	**(51.6)**	(20.6)	**(65.6)**	(27.5)
Net Utility Sales - electricity	**135.4**	26.3	**172.2**	35.0
Utility natural gas sales and distribution	**109.8**	85.1	**140.0**	114.0
Less: cost of sales – natural gas	**(53.1)**	(39.8)	**(67.7)**	(53.2)
Net Utility Sales - natural gas	**56.7**	45.3	**72.3**	60.8
Utility water distribution & wastewater treatment sales and distribution	**31.5**	31.7	**40.1**	42.3
Less: cost of sales – water	**(2.4)**	(2.2)	**(3.1)**	(3.0)
Net Utility Sales - water distribution & wastewater treatment	**29.1**	29.5	**37.0**	39.3
Gas transportation	**9.6**	8.4	**12.3**	10.7
Other revenue	**5.1**	5.0	**6.5**	6.8
Net Utility Sales	**235.9**	114.5	**300.3**	152.6
Operating expenses	**(96.6)**	(50.5)	**(123.1)**	(68.0)
Other income	**1.4**	0.9	**1.8**	1.3
HLBV	**1.3**	—	**1.7**	—
Divisional Operating Profit[1]	**$ 142.0**	$ 64.9	**$ 180.7**	$ 85.9

1 Certain prior year items have been reclassified to conform with current year presentation.

For the three months ended December 31, 2017, the Liberty Utilities Group reported an operating profit (excluding corporate administration expenses) of U.S. $142.0 million as compared to U.S. $64.9 million for the comparable period in the prior year. Measured in Canadian dollars, the Group's operating profit was $180.7 million as compared to $85.9 million during the same period in 2016, which represents an increase of $94.8 million or 110%, 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	**$**	**85.9**
Existing Facilities		
Electricity: Decrease primarily due to retroactive recognition of 12 months of revenue in Q4 of 2016 arising from the 2016 rate case at the Calpeco Electric System.		(6.4)
Gas: Increase primarily due to higher consumption at the Midstates and EnergyNorth Gas Systems.		3.1
Water: Decrease primarily due to lower revenue as a result of the disposition of the Mountain Water System in Montana.		(2.2)
Other: Decrease primarily due to lower contracted services.		(0.1)
		(5.6)
New Facilities		
Electricity: Acquisition of both Empire's electric distribution system ($85.9 million) on January 1, 2017 and the Luning Solar Facility ($4.9 million) on February 15, 2017.		90.8
Gas: Acquisition of Empire's gas distribution system on January 1, 2017.		4.3
Water: Acquisition of Empire's water distribution system on January 1, 2017.		0.3
Other: Acquisition of Empire's fiber optic operations on January 1, 2017.		1.9
		97.3
Rate Cases		
Electricity: Implementation of new rates at the Granite State Electric System.		1.0
Gas: Implementation of new rates at the EnergyNorth, Midstates, New England, and Peach State Gas Systems.		4.1
Water: Implementation of new rates at the Park Water System.		2.0
		7.1
Foreign Exchange		**(4.0)**
Current Period Divisional Operating Profit	**$**	**180.7**

2017 **Annual** Usage Results

Electric Distribution Systems

	Twelve Months Ended December 31	
	2017	**2016**
Average Active Electric Connections For The Period		
Residential	223,700	80,400
Commercial and industrial	39,200	12,500
Total Average Active Electric Connections For The Period	**262,900**	**92,900**
Customer Usage (GW-hrs)		
Residential	2,320.1	567.0
Commercial and industrial	3,523.1	895.2
Total Customer Usage (GW-hrs)	**5,843.2**	**1,462.2**

For the twelve months ended December 31, 2017 , the electric distribution systems' usage totaled 5,843.2 GW-hrs as compared to 1,462.2 GW-hrs for the same period in 2016, an increase of 4,381.0 GW-hrs. The addition of Empire accounted for 4,386.3 GW-hrs of the increase. Excluding Empire, usage was 5.3 GW-hrs, or 0.4%, lower due to decreased usage by commercial customers at the Granite State Electric System.

Natural Gas Distribution Systems

	Twelve Months Ended December 31	
	2017	2016
Average Active Natural Gas Connections For The Period		
Residential	287,100	249,000
Commercial and industrial	31,700	26,600
Total Average Active Natural Gas Connections For The Period	**318,800**	**275,600**
Customer Usage (MMBTU)		
Residential	17,621,000	15,346,000
Commercial and industrial	12,672,000	11,361,000
Total Customer Usage (MMBTU)	**30,293,000**	**26,707,000**

For the twelve months ended December 31, 2017, usage at the natural gas distribution systems totaled 30,293,000 MMBTU as compared to 26,707,000 MMBTU during the same period in 2016, an increase of 3,586,000 MMBTU or 13.4%. The addition of Empire accounted for 2,997,000 MMBTU of the increase. Excluding Empire, usage was 589,000 MMBTU, or 2.2%, higher due to increased usage at the EnergyNorth and New England Gas Systems.

Water and Wastewater Distribution Systems

	Twelve Months Ended December 31	
	2017	2016
Average Active Connections For The Period		
Wastewater connections	41,000	41,100
Water distribution connections	121,400	131,400
Total Average Active Connections For The Period	**162,400**	172,500
Gallons Provided		
Wastewater treated (millions of gallons)	2,226	2,231
Water provided (millions of gallons)	16,905	17,936
Total Gallons Provided	**19,131**	20,167

During the twelve months ended December 31, 2017, the water and wastewater distribution systems provided approximately 16,905 million gallons of water to its customers and treated approximately 2,226 million gallons of wastewater as compared to 17,936 million gallons of water and 2,231 million gallons of wastewater during the same period in 2016. The decrease in the gallons of water provided to customers can be attributed to the disposition of the Mountain Water System in Montana. Excluding the Mountain Water System, the water provided to customers was approximately 2,295 million gallons, or 14%, higher.

2017 **Annual** Operating Results

	Twelve Months Ended December 31			
	2017 U.S. $ (millions)	2016 U.S. $ (millions)	2017 Can $ (millions)	2016 Can $ (millions)
Revenue				
Utility electricity sales and distribution	**$ 763.5**	$ 171.7	**$ 989.2**	$ 228.1
Less: cost of sales – electricity	**(222.4)**	(90.0)	**(288.2)**	(119.8)
Net Utility Sales - electricity	**541.1**	81.7	**701.0**	108.3
Utility natural gas sales and distribution	**346.0**	276.8	**450.7**	371.4
Less: cost of sales – natural gas	**(141.7)**	(105.0)	**(184.5)**	(142.1)
Net Utility Sales - natural gas	**204.3**	171.8	**266.2**	229.3
Utility water distribution & wastewater treatment sales and distribution	**140.1**	137.4	**181.9**	181.7
Less: cost of sales – water	**(9.5)**	(9.2)	**(12.3)**	(12.2)
Net Utility Sales - water distribution & wastewater treatment	**130.6**	128.2	**169.6**	169.5
Gas transportation	**31.2**	25.7	**40.7**	34.3
Other revenue	**11.8**	11.0	**15.2**	14.6
Net Utility Sales	**919.0**	418.4	**1,192.7**	556.0
Operating expenses	**(393.7)**	(196.1)	**(512.0)**	(260.6)
Other income	**4.2**	3.9	**5.4**	5.1
HLBV	**6.2**	—	**8.0**	—
Divisional Operating Profit[1]	**$ 535.7**	$ 226.2	**$ 694.1**	$ 300.5

1 Certain prior year items have been reclassified to conform with current year presentation.

For the twelve months ended December 31, 2017, the Liberty Utilities Group reported an operating profit (excluding corporate administration expenses) of U.S. $535.7 million as compared to U.S. $226.2 million for the comparable period in the prior year. Measured in Canadian dollars, the Group's operating profit was $694.1 million as compared to $300.5 million during the same period in 2016, which represents an increase of $393.6 million or 131%, 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	**$**	**300.5**
Existing Facilities		
Gas: Increase primarily due to higher consumption at the EnergyNorth Gas System.		4.5
Water: Decrease primarily due to lower revenue as a result of the disposition of the Mountain Water System in Montana.		(5.3)
Other: Decrease primarily due to lower contracted services.		(3.7)
		(4.5)
New Facilities		
Electricity: Acquisition of both Empire's electric distribution system ($341.4 million) on January 1, 2017 and the Luning Solar Facility ($20.7 million) on February 15, 2017.		362.1
Gas: Acquisition of Empire's gas distribution system on January 1, 2017.		11.9
Water: Acquisition of Empire's water distribution system on January 1, 2017.		1.3
Other: Acquisition of Empire's fiber optic operations on January 1, 2017.		5.7
		381.0
Rate Cases		
Electricity: Implementation of new rates at the Granite State Electric System.		5.2
Gas: Implementation of new rates at the EnergyNorth, Midstates, New England, and Peach State Gas Systems.		12.5
Water: Implementation of new rates at the Park Water, Bella Vista, Rio Rico and Black Mountain Water and Wastewater Systems.		6.1
		23.8
Foreign Exchange		**(6.7)**
Current Period Divisional Operating Profit	**$**	**694.1**

Regulatory Proceedings

The following table summarizes the major regulatory proceedings currently underway within the Liberty Utilities Group:

Utility	State	Regulatory Proceeding Type	Rate Request U.S. $ (millions)	Current Status
Completed Rate Cases				
Granite State Electric System	New Hampshire	General Rate Case ("GRC")	$7.7	Final Order issued in April 2017 approving a U.S. $6.2 million rate increase effective May 1, 2017, and two additional rate increases of approximately U.S. $0.2 million and U.S. $0.3 million effective May 1, 2018 and May 1, 2019, respectively.
New England Gas	Massachusetts	Gas System Enhancement Plan ("GSEP")	$3.8	Final Order issued in April 2017 approving a U.S. $2.9 million rate increase effective May 1, 2017.
Illinois Gas System	Illinois	GRC	$3.0	Final Order issued in May 2017 approving a U.S. $2.2 million rate increase effective June 7, 2017.
Oklahoma Electricity System	Oklahoma	GRC	$3.0	In August 2017, in lieu of authorizing the proposed rate increase the Oklahoma Corporation Commission ordered an immediate increase of U.S. $1.0 million to capture the return on and of major capital investments related to plant upgrades and authorized Liberty Utilities to return in 2018 to seek the remaining proposed increases.
Calpeco Electric	California	Turquoise Solar Project	$3.0	Final Order issued in December 2017 approving the Settlement Agreement between Liberty Calpeco and the Office of Ratepayer Advocates dated June 30, 2017 which authorizes Liberty Calpeco to acquire, own, and operate the 10 MW, U.S. $15.7 million Turquoise Solar Project.
Calpeco Electric	California	Post-Test Year Adjustment Mechanism	$2.2	Final Order issued in November 2017 approving a U.S $2.2 million rate increase effective January 1, 2018, based on the additional costs related to the Luning Solar Project.
Various	Various	Various	$4.8	Other rate cases closed in 2017 & 2018 with a combined approved rate increase of U.S. $2.8 million include: Entrada Del Oro Water (U.S. $0.2 million), Georgia Gas GRAM (U.S. $0.6 million), New England Gas Decoupling (U.S. $0.2 million), Iowa Gas GRC (U.S. $0.9 million), and Kansas Asbury Environmental and Riverton Cost Recovery Rider (U.S. $0.9 million).

Utility	State	Regulatory Proceeding Type	Rate Request U.S. $ (millions)	Current Status
Pending Rate Cases				
EnergyNorth Gas System	New Hampshire	GRC	$19.7	On April 28, 2017, filed an application seeking an increase of U.S. $13.7 million (updated to U.S. $14.5 million), plus a step increase of U.S. $6.1 million (updated to U.S. $5.2 million) to be implemented in May 2018. Temporary rates of U.S. $7.8 million were requested to be effective as of July 1, 2017, and on June 30, 2017, the New Hampshire Public Utilities Commission (“NH Commission”) approved temporary rates of U.S. $6.8 million (87% of the requested amount) effective July 1, 2017 to be in place until the end of the Company's permanent rate case.
Litchfield Park Water & Sewer	Arizona	GRC	$5.1	On February 28, 2017, filed a water/sewer rate application (test year December 31, 2016) seeking a rate increase of U.S. $5.1 million. New rates are expected to be effective in Q4 2018.
Missouri Gas System	Missouri	GRC	$7.5	On September 29, 2017, filed an application seeking a rate increase of U.S. $7.5 million for test year ending June 30, 2017 with proforma adjustments through to March 31, 2018. New rates are expected to be effective in Q3 2018.
Apple Valley Ranchos Water & Park Water Systems	California	GRC	$2.1	On January 2, 2018, filed an application requesting an average rate increase of U.S. $0.7 million and U.S. $1.4 million, respectively and is to set rates for the three year period of 2019 to 2021.
New England Natural Gas System	Massachusetts	GSEP	$6.2	On October 31, 2017, filed the 2018 GSEP application requesting recovery of U.S. $6.2 million (effective May 1, 2018) for replacement of approximately 14 miles of eligible infrastructure.
Various	Various	Various	$4.3	Other pending rate case requests include: Woodmark/Tall Timbers Wastewater Systems (U.S. $1.6 million), Park Water System (U.S. $1.5 million), and Missouri Water System (U.S. $1.2 million).

Completed Rate Cases

On December 14, 2016, the Calpeco Electric System filed an application for approval of the 10 MW Turquoise Solar Project at an estimated cost of U.S. $15.7 million. On June 30, 2017, the Calpeco Electric System and the Office of Ratepayer Advocates filed a joint motion with the Commission requesting approval of its settlement agreement. On December 19, 2017, the Commission issued a decision approving the settlement agreement as filed. The Turquoise Solar Project costs will be included in the Calpeco Electric System's 2019 general rate case and is expected to have a rate impact of approximately U.S. $3.0 million (or 3% increase), which will be offset by future Energy Cost Adjustment Clause ("ECAC)" account reductions. The Turquoise Solar Project is expected to be in service by the fourth quarter of 2018.

On April 29, 2016, the Granite State Electric System filed a rate application seeking a U.S. $5.3 million annual revenue increase proposed for effect July 1, 2016, plus an additional U.S. $2.4 million annual step increase to recover the revenue requirement associated with capital additions made in 2016. The total permanent and step increase proposed was U.S. $7.7 million annually, or a 21.8% increase to distribution revenue. In June 2016, approval of a temporary rate increase of U.S. $2.4 million was issued, effective July 1, 2016. The final permanent rate increase was retroactive to the temporary rate effective date. In April 2017, an order was issued by the New Hampshire Public Utilities Commission ("NHPUC") approving a U.S. $3.8 million rate increase to annual distribution revenues along with an annual increase of U.S. $2.5 million for the revenue requirement associated with 2016 capital investment, both effective May 1, 2017 (achieving 82% of the requested increase). The difference between the U.S. $3.8 million permanent increase and the U.S. $2.4 million temporary rate level that was in effect since July 1, 2016 was collected beginning May 1, 2017. The settlement also provides for two additional annual increases of approximately U.S. $0.2 million and $0.3 million effective May 1, 2018 and May 1, 2019, respectively, to recover the revenue requirement associated with certain significant capital investments made during the prior calendar year.

Pending Regulatory Proceedings

On October 31, 2017, Empire District Electric Company announced a proposed plan to expand its wind resources with the development of up to an additional 800 MW of strategically located wind generation in or near its service territory by the end of 2020. Once fully operational, the project is projected to generate cost savings for customers of U.S. $172.0 million - U.S. $325.0 million over a twenty-year period. Empire filed a request for approval ("Application") of the wind expansion initiative with regulators in Missouri, Kansas, Oklahoma, and Arkansas, and the project is subject to their respective review. On February 6, 2018, the staff of the Missouri Public Service Commission as well as other intervenors filed testimony responsive to the Application. The staff's testimony recommends that the Commission should either approve the projects with conditions or rule that it need not provide approval for the projects to proceed, while other intervenors range in their recommendations from suggesting that the Commission not approve the project to recommending outright approvals. Testimony has now also been received in Oklahoma and Arkansas. In Oklahoma both the staff and the Attorney General recommended approval of the projects and in Arkansas additional details were requested on the proposed projects. The Liberty Utilities Group's local regulatory teams continue to work closely with staffs and commissions from the regulatory agencies and anticipate securing approvals for the projects by June 2018.

CORPORATE DEVELOPMENT ACTIVITIES

The Corporate Development Group works to identify, develop and construct new power generating facilities as well as to identify and acquire operating projects that would be complementary and accretive to the Liberty Power Group's existing portfolio and the Company as a whole. The Corporate Development Group is focused on projects within North America and is committed to working proactively with all stakeholders including local communities.

The development and construction of new power generation facilities involves a number of risks and uncertainties including scheduling delays, cost over runs and other events that may be beyond the control of the Company (See *Operational Risk Management - Development and Construction Risk*).

The Corporate Development Group's approach to project development and acquisition is to maximize the utilization of internal resources while minimizing external costs. This approach allows projects to mature to the point where most major elements and uncertainties are quantified and resolved prior to the commencement of project construction. Major elements and uncertainties of a project include the signing of a PPA, obtaining the required financing commitments to develop the project, completion of environmental and other required permitting, and fixing the cost of the major capital components of the project. It is not until all major aspects of a project are secured that the Corporate Development group will begin construction or execute an acquisition agreement.

Each of the projects contained in the table below meet the following criteria: a proven wind or solar resource, a signed PPA with a credit-worthy counterparty, and satisfaction of the Company's investment return objectives. The projects are as follows:

Project Name	Location	Size (MW)	Estimated Capital Cost Range (millions)[1]	Commercial Operation	PPA Term (Years)	Production (GW-hrs)
Projects in Construction						
Amherst Island Wind Project	Ontario	75	$ 320 - $ 350	2018	20	235
Great Bay Solar Project[2]	Maryland	75	169 - 188	2018	10	146
Total Projects in Construction		**150**	**$ 489 - $ 538**			**381**
Projects in Development						
Blue Hill Wind Project	Saskatchewan	177	$ 315 - $ 350	2019/20	25	813
Val-Eo Wind Project[3]	Quebec	24	60 - 70	2018	20	66
Turquoise Solar Project[4]	Nevada	10	25 - 31	2018		28
Total Projects in Development		**211**	**$ 400 - $ 451**			**907**
Total in Construction and Development		**361**	**$ 889 - $ 989**			**1,288**

[1] Estimated capital costs for U.S. based projects have been converted at the exchange rate in effect at the end of the current reporting period.

[2] The total cost of the project is expected to be approximately U.S. $135 - U.S. $150 million. Two of the four Great Bay Solar sites achieved COD in December 2017 while the remaining two sites are expected to achieve COD in the first quarter of 2018.

[3] All figures refer solely to Phase I of the Val-Eo Wind Project.

[4] The Turquoise Solar Project will be included in the rate base of the Calpeco Electric System (see *Regulatory Proceedings*). The total cost of the project is expected to be approximately U.S. $20.0 - U.S. $25.0 million.

Projects Completed

Deerfield Wind Project

The Deerfield Wind Project is a 150 MW wind powered electric generating development project located in central Michigan and is constructed on approximately 20,000 acres of land leased from a supportive wind power land owner group.

Construction of the project commenced in the fourth quarter of 2015. The project declared commercial operations on February 21, 2017.

The project is the Liberty Power Group's tenth wind generating facility and consists of 44 Vestas V110-2.0 wind turbines and 28 Vestas V110-2.2 turbines and is estimated to generate 555.2 GW-hrs of energy per year, with all energy, capacity, and renewable energy credits from the project sold to a local electric distribution utility which serves 260,000 customers in Michigan, pursuant to a 20 year PPA.

The Liberty Power Group's initial interest in the project was via a 50% joint venture with the original developer along with an option to acquire the other 50% interest. On March 14, 2017, the Liberty Power Group exercised its option and purchased the remaining 50% interest in the project for U.S. $21.6 million.

The project qualified for U.S. federal production tax credits, and consistent with financing structures utilized for U.S. based renewable energy projects, approximately U.S. $166.6 million of financing for the project was received from tax equity investors in May 2017.

Bakersfield II Solar Project

The Bakersfield II Solar Project is a 10 MWac solar powered electric generating project adjacent to the Liberty Power Group's 20 MW Bakersfield I Solar Project in Kern County, California.

Construction of the project commenced in the second quarter of 2015. The facility declared commercial operations on January 11, 2017.

The facility is the Liberty Power Group's third solar generating facility and is comprised of approximately 38,640 solar panels located on 64 acres of land. The project is expected to generate 24.2 GW-hrs of energy per year which is being sold under a 20 year PPA with a large investment grade electric utility.

The project qualified for U.S. federal investment tax credits, and consistent with financing structures utilized for U.S. based renewable energy projects, approximately U.S. $12.3 million of financing for the project was sourced from a tax equity investor. The tax equity financing closed on February 28, 2017, following achievement of commercial operations.

Projects in Construction

Amherst Island Wind Project

The Amherst Island Wind Project is a 75 MW wind powered electric generating development project located on Amherst Island near the village of Stella, approximately 15 kilometers southwest of Kingston, Ontario.

The project is currently contemplated to use Class III wind turbine generator technology consisting of 26 Siemens 3.0 MW turbines and is expected to produce approximately 235.0 GW-hrs of electrical energy annually, with all energy being sold under a 20 year PPA awarded as part of the Independent Electricity System Operator ("IESO"), formerly the Ontario Power Authority, Feed in Tariff ("FIT") program.

Liberty Power's interest in the project is via a 50% joint venture. Liberty Power has an option to acquire the other 50% interest, subject to certain adjustments, after COD and prior to January 15, 2019.

The total costs to complete the project are estimated at approximately $320.0 million to $350.0 million. The increase in the expected range of construction costs are primarily the result of additional winter construction days than previously anticipated. As the Company refines its operating model for post COD, it has identified new operational costs savings of approximately $10.0 million which are expected to be realized over the life of the project. Construction over the fall and winter months has focused primarily on building access roads, foundations and receiving turbine components.

Manufacturing of major equipment is now complete and turbine deliveries commenced in November 2017, with all turbines expected to be delivered by March 2018. To date, two turbines have been erected and the foundation for the power transformer housing is complete. The main power transformer was delivered to the site in early February 2018. A 115kV submarine cable was also successfully installed during 2017. Subject to receipt of ongoing construction-related permitting, construction is expected to be substantially completed in the second quarter of 2018.

Placement of construction debt closed in the fourth quarter of 2017 with a consortium of major financial institutions for a total commitment of $260.4 million.

Great Bay Solar

The Great Bay Solar Project is a 75 MWac solar powered electric generating development project comprised of four sites located in Somerset County in southern Maryland.

The facility is comprised of 300,000 solar panels and is being constructed on 400 acres of land. The project is expected to generate 146.0 GW-hrs of energy per year, with all energy sold to the U.S. Government Services pursuant to a 10 year PPA, with a 10 year extension option. All Solar Renewable Energy Credits from the project will be retained by the project company and sold into the Maryland market.

The project received its Certificate of Public Convenience and Necessity from the State of Maryland Public Service Commission and building permits from the Somerset County Building and Zoning Department. Both the balance of plant and high voltage engineering, procurement, and construction contracts have been executed.

The total costs to complete the project are estimated at approximately U.S. $135.0 million to U.S. $150.0 million. The project achieved partial completion in late 2017, producing revenue on 25 MW of the full site capacity. Approximately U.S. $59.0 million of the permanent project financing will come from tax equity investors. As of December 31, 2017, the project has received U.S $42.8 million in project funding, with the remaining expected to be received in the first half of 2018.

Projects in Development

Blue Hill Wind Project

The Blue Hill Wind Project is a 177 MW wind powered electric generating development project located in the rural municipalities of Lawtonia and Morse in southwest Saskatchewan.

The project is expected to generate 813.0 GW-hrs of energy per year, with all energy sold to SaskPower pursuant to a 25 year PPA originally awarded in 2012 and amended in 2016.

The project requires development permits as well as final environmental approval. The Environmental Impact Study was completed and submitted to the Saskatchewan Ministry of Environment in the fourth quarter of 2017. Stakeholder engagement continued through 2017 with relevant government officials, NGOs, landowners and the community through open houses and in-person meetings.

The total costs to complete the project are estimated at approximately $315.0 million to $350.0 million. SaskPower recently completed an interim system impact study for the wind turbine generators, which was received in the fourth quarter of 2017. A geotechnical evaluation of the project site and existing infrastructure began in the fourth quarter of 2017, with results expected in early 2018. Preparation and submission of the development permit is expected in the first quarter of 2018.

Val-Éo Wind Project

The Val-Éo Wind Project is a 125 MW wind powered electric generating development project located in the local municipality of Saint-Gideon de Grandmont, which is within the regional municipality of Lac-Saint-Jean-Est, Quebec. The project proponents include the Val-Éo Wind Cooperative which was formed by community based landowners and the Liberty Power Group.

The Liberty Power Group has a 50% economic equity interest in the project. It is believed that the first 24 MW phase of the Val-Éo Wind Project will qualify as Canadian Renewable Conservation Expense and, therefore, the project will be entitled to a refundable tax credit equal to approximately $16.0 million.

The project will be developed in two phases: Phase I of the project is expected to be completed in 2018 and will likely comprise ten 2.35 MW wind turbines for a total capacity of 24 MW and is expected to generate 66.0 GW-hrs of energy per year, with all energy from Phase I of the project to be sold to Hydro-Quebec pursuant to a 20 year PPA; Phase II of the project would entail the development of an additional 101 MW and would be constructed following the successful evaluation of the wind resource at the site, completion of satisfactory permitting and entering into appropriate energy sales arrangements.

The total costs to complete Phase I of the project are estimated at approximately $60.0 million to $70.0 million. All land agreements, construction permits, and authorizations have been obtained for Phase I. The new schedule calls for Phase I construction to begin in the second quarter of 2018, with commissioning to occur in the fourth quarter of 2018.

Turquoise Solar Project

The Turquoise Solar project is a 10 MW solar powered electric generating development project located in Washoe County in Nevada.

The facility is comprised of 108,000 solar thin film panels on a tracker system and is being constructed on 110 acres of land. The Turquoise Solar Project is expected to generate 28 GW-hrs of energy per year and to be included in the rate base of the Calpeco Electric System as energy produced from the project will be consumed by the utility's customers (see *Regulatory Proceedings*).

The project has been approved by the California PUC, and mechanical completion is expected in the fourth quarter of 2018.

The total costs to complete the project are estimated at approximately U.S. $20.0 million to U.S. $25.0 million. The Liberty Utilities Group expects the project will qualify for U.S. federal investment tax credits and accordingly, approximately 30% of the permanent financing is expected to be funded by tax equity investors.

APUC: CORPORATE AND OTHER EXPENSES

(all dollar amounts in $ millions)	Three Months Ended December 31		Twelve Months Ended December 31	
	2017	2016	2017	2016
Corporate and other expenses:				
Administrative expenses	**$ 18.7**	$ 13.1	**$ 64.5**	$ 46.3
(Gain)/Loss on foreign exchange	**1.6**	1.3	**0.4**	(0.4)
Interest expense on convertible debentures and acquisition facility related to the Empire Acquisition	**—**	18.2	**17.6**	57.6
Interest expense	**42.4**	20.5	**185.0**	74.0
Interest, dividend, equity, and other income [1]	**(0.6)**	(3.1)	**(2.8)**	(5.3)
Other losses (gains)	**4.7**	(0.8)	**0.6**	(11.8)
Acquisition-related costs	**1.3**	2.4	**62.8**	12.0
Loss (gain) on derivative financial instruments	**(4.0)**	(12.9)	**(2.6)**	(15.8)
Income tax expense	**38.0**	11.5	**95.2**	37.1

[1] Excludes income directly pertaining to the Liberty Power and Liberty Utilities Groups (disclosed in the relevant sections).

U.S. Tax Reform

On December 22, 2017, H.R. 1, the Tax Cuts and Jobs Act ("U.S. Tax Reform" or the "Act"), was signed into law which resulted in significant changes to U.S. tax law. Key provisions of U.S. Tax Reform include the following:

- U.S. federal corporate income tax rate reduction from 35 per cent to 21 per cent effective January 1, 2018.
- The corporate alternative minimum tax ("AMT") is eliminated effective January 1, 2018.
- The Base Erosion Anti-Abuse Tax ("BEAT") is a new minimum tax computed each year and is generally the excess of (a) 10% of the taxpayer's "modified taxable income" over (b) the taxpayer's regular tax liability reduced by its tax credits.
- Other than for regulated utilities, interest deductibility is limited to 30 per cent of EBITDA from 2018 to 2021 and 30 per cent of EBIT after 2021.
- Other than for regulated utilities, immediate expensing of 100 per cent of the cost of new investments made in qualified depreciable assets after September 27, 2017.
- The production tax credit (the "PTC") of Section 45 of the Code and the investment tax credit (the "ITC") of Section 48 of the Code are left unchanged by the Act and the elimination of the AMT ensures that renewable energy tax credits will continue to be valuable to tax equity investors.
- The Act allows taxpayers until 2025 to offset any tax owed under the BEAT by 80% of the value of the PTCs and the ITCs for renewable energy projects.
- No change was made to the "continuous construction" requirement for determining when construction of a project commences.

As a result of these changes, the Company has remeasured existing deferred income tax assets and deferred income tax liabilities related to our U.S. regulated and non-regulated businesses to reflect the new lower income tax rate as at December 31, 2017. This remeasurement resulted in a one-time non-cash accounting charge of $22.4 million and is recorded in the Company's 2017 consolidated statement of operations.

Future Impacts

Beginning in 2018, the Company expects its effective tax rate on consolidated worldwide net income to be below 20%.

The Company expects that the effects of U.S. Tax Reform in 2018 will be neutral to slightly positive to EPS and approximately 2%-3% negative to 2018 EBITDA, which is within the planning parameters that APUC establishes for normal variability in its business cycle from wind, hydrology and weather.

The Company believes that most of its U.S. holding company interest can be properly allocable in accordance with the Act to its U.S. regulated utilities and is therefore largely exempted from the interest deductibility limitations.

It is expected there will be no material changes to the Company's U.S. regulated utilities' future net earnings, specifically as it pertains to U.S. Tax Reform since normal rate making processes would see the lower income tax expense and amortization of the deferred tax revaluation regulatory liability offset by lower customer rates over time. However, the Company believes that all stakeholders are best served by dealing with U.S. Tax Reform within the context of a full regulatory rate case proceeding, where all factors that comprise rates can be considered including investments in rate base, recovery of operating costs, capital structure and cost of capital.

APUC views that going forward the lower tax rates can enable accelerated investment over time in our regulated utilities to deliver an improved customer experience and more reliable service with less of an impact on customer rates than would otherwise occur.

APUC continues to believe that with the provisions in the Act for PTCs and ITCs, between the Company's ability to absorb a part of the renewable energy tax credits in future years and anticipated future demand from third party tax equity investors wishing to avail themselves of renewable energy tax credits, the Company will be able to satisfy the tax equity financing component for its U.S. renewable energy projects over the next three to five years.

SEC Guidance

The U.S. Securities and Exchange Commission ("SEC") has issued guidance allowing registrants to record provisional amounts which may be adjusted as information over time becomes available, prepared or analyzed during a measurement period not to exceed one year.

The SEC guidance summarizes a three-step process to be applied at each reporting period to identify: (1) where the accounting is complete; (2) provisional amounts where the accounting is not yet complete, but a reasonable estimate has been determined; and (3) where a reasonable estimate cannot yet be determined and therefore income taxes are reflected in accordance with tax laws in effect prior to the enactment of the Act.

At December 31, 2017, APUC considers all amounts recorded related to U.S. Tax Reform to be reasonable estimates. Given that APUC's utility businesses are regulated, the Company's interpretation, assessment and presentation of the impact of U.S. Tax Reform may be further clarified with additional guidance from regulatory, tax and accounting authorities. Should additional information emerge that affects current estimates during this one-year measurement period allowed for by the SEC, adjustments will be made to the provisional amounts as appropriate.

2017 Fourth Quarter Corporate and Other Expenses

During the three months ended December 31, 2017, administrative expenses totaled $18.7 million as compared to $13.1 million in the same period in 2016. The $5.6 million increase primarily relates to additional costs incurred to administer APUC's operations as a result of the Company's growth, including ongoing administration expenses related to Empire.

For the three months ended December 31, 2017, interest expense on convertible debentures and bridge financing totaled $nil as compared to $18.2 million in the same period in 2016.

For the three months ended December 31, 2017, interest expense totaled $42.4 million as compared to $20.5 million in the same period in 2016. The interest expense for the period is primarily attributable to assumed and incremental debt related to the Empire Acquisition, and new debt raised by the Liberty Power and Liberty Utilities Groups.

For the three months ended December 31, 2017, other losses were $4.7 million as compared to gains of $0.8 million in the same period in 2016. The increase in current period losses is primarily attributable to an increase in regulatory liabilities in the LPSCo Water System resulting from ongoing regulatory proceedings.

For the three months ended December 31, 2017, gains on derivative financial instruments totaled $4.0 million as compared to $12.9 million in the same period in 2016. The increase in 2016 was primarily driven by mark-to-market gains on foreign currency derivatives.

For the three months ended December 31, 2017, an income tax expense of $38.0 million was recorded as compared to an income tax expense of $11.5 million during the same period in 2016. The increase in income tax expense is primarily due to the Empire Acquisition and a one-time non-cash accounting charge of $22.4 million related to the revaluation of the Company's U.S. non-regulated net deferred income tax assets as a result of U.S. Tax Reform (see *U.S. Tax Reform* for additional information).

2017 Annual Corporate and Other Expenses

During the twelve months ended December 31, 2017 , administrative expenses totaled $64.5 million as compared to $46.3 million in the same period in 2016. The increase primarily relates to additional costs incurred to administer APUC's operations as a result of the Company's growth, including ongoing administration expenses related to Empire.

For the twelve months ended December 31, 2017 , interest expense on convertible debentures and bridge financing totaled $17.6 million as compared to $57.6 million in the same period in 2016 (see *note 14* in the financial statements).

For the twelve months ended December 31, 2017 , interest expense totaled $185.0 million as compared to $74.0 million in the same period in 2016. The increase in interest expense for the period is primarily attributable to assumed and incremental debt related to the Empire Acquisition, and new debt raised by the Liberty Power and Liberty Utilities Groups. (See *Credit Facilities & Debt* and *note 9* in the financial statements).

For the twelve months ended December 31, 2017 , other losses were $0.6 million as compared to a gain of $11.8 million in the same period in 2016. The prior period gains primarily resulted from: (i) the recognition of deferred income on repairs completed for facilities where the insurance proceeds have been received in advance; and (ii) the settlement of litigation and bankruptcy proceedings relating to Trafalgar Power Inc. (see *note 18* in the financial statements) partially offset by (iii) the write-down of the Company's equity interest in natural gas development projects that have been canceled by the developer.

For the twelve months ended December 31, 2017 , acquisition-related costs totaled $62.8 million as compared to $12.0 million in the same period in 2016. The increase is primarily attributable to the Empire Acquisition.

For the twelve months ended December 31, 2017 , the gain on derivative financial instruments totaled $2.6 million as compared to a gain of $15.8 million in the same period in 2016. The gain in 2016 was due to market-to-market gains on foreign currency hedges offset by losses on the ineffective portion of derivative financial instruments accounted for as derivatives.

An income tax expense of $95.2 million was recorded in the twelve months ended December 31, 2017 as compared to an income tax expense of $37.1 million during the same period in 2016. The increase in income tax expense is primarily due to the Empire Acquisition, the tax effect related to the Mountain Water condemnation, and a one-time non-cash accounting charge of $22.4 million related to the revaluation of the Company's U.S. non-regulated net deferred income tax assets as a result of U.S. Tax Reform (see *U.S. Tax Reform* for additional information).

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)	**2017**	**2016**	**2017**	**2016**
Net earnings attributable to shareholders	**$ 60.0**	$ 46.3	**$ 193.1**	$ 130.9
Add (deduct):				
Net earnings attributable to the non-controlling interest, exclusive of HLBV	**0.8**	(0.8)	**3.2**	7.5
Income tax expense	**38.0**	11.5	**95.2**	37.1
Interest expense on convertible debentures and bridge financing	**—**	18.2	**17.6**	57.6
Interest expense on long-term debt and others	**42.4**	20.5	**185.0**	74.0
Other losses (gains)	**4.8**	(0.8)	**0.7**	(11.9)
Acquisition-related costs	**1.3**	2.4	**62.8**	12.0
Costs related to tax equity financing	**0.5**	—	**2.3**	—
Loss (gain) on derivative financial instruments	**(4.0)**	(12.9)	**(2.6)**	(15.8)
Realized loss on energy derivative contracts	**—**	—	**(0.7)**	(1.0)
Loss (gain) on foreign exchange	**1.6**	1.3	**0.4**	(0.4)
Depreciation and amortization	**88.0**	52.6	**326.4**	186.9
Adjusted EBITDA	**$ 233.4**	$ 138.3	**$ 883.4**	$ 476.9

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, 2017 amounted to $14.3 million and $67.8 million as compared to $13.6 million and $41.0 million during the same period in 2016.

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)	**2017**	**2016**	**2017**	**2016**
Net earnings attributable to shareholders	**$ 60.0**	$ 46.3	**$ 193.1**	$ 130.9
Add (deduct):				
Loss (gain) on derivative financial instruments	**(4.0)**	(12.9)	**(2.6)**	(15.8)
Realized loss on derivative financial instruments	**—**	—	**(0.7)**	(1.0)
Loss (gain) on long-lived assets, net	**1.5**	(0.8)	**(2.5)**	(3.3)
Loss (gain) on foreign exchange	**1.6**	1.3	**0.4**	(0.4)
Interest expense on convertible debentures and acquisition financing	**—**	18.2	**17.6**	57.6
Acquisition-related costs	**1.3**	2.4	**62.8**	12.0
Costs related to tax equity financing	**0.5**	—	**2.3**	—
Other adjustments	**3.2**	—	**3.2**	—
U.S. Tax Reform adjustment [2]	**22.4**		**22.4**	
Adjustment for taxes related to above	**(0.6)**	(3.1)	**(3.9)**	(18.4)
Adjusted Net Earnings	**$ 85.9**	$ 51.4	**$ 292.1**	$ 161.6
Adjusted Net Earnings per share [1]	**$ 0.20**	$ 0.18	**$ 0.74**	$ 0.57

[1] Per share amount calculated after preferred share dividends and excluding subscription receipts issued for projects or acquisitions not reflected in earnings.

[2] Represents the one-time non-cash accounting charge related to the revaluation of U.S. non-regulated net deferred income tax assets as a result of U.S. Tax Reform (see *U.S. Tax Reform* for additional information).

For the three months ended December 31, 2017, Adjusted Net Earnings totaled $85.9 million as compared to Adjusted Net Earnings of $51.4 million for the same period in 2016, an increase of $34.5 million. The increase in Adjusted Net Earnings for the three months ended December 31, 2017 is primarily due to increased earnings from operations partially offset by higher depreciation and amortization expense as compared to 2016.

For the twelve months ended December 31, 2017 , Adjusted Net Earnings totaled $292.1 million as compared to Adjusted Net Earnings of $161.6 million for the same period in 2016, an increase of $130.5 million. The increase in Adjusted Net Earnings for the twelve months ended December 31, 2017 is primarily due to increased earnings from operations partially offset by higher depreciation and amortization expense as compared to 2016.

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)	2017	2016	2017	2016
Cash flows from operating activities	**$ 169.8**	$ 121.9	**$ 457.8**	$ 287.9
Add (deduct):				
Changes in non-cash operating items	**(12.0)**	(46.7)	**74.0**	(3.7)
Production based cash contributions from non-controlling interests	**—**	0.6	**10.6**	11.2
Interest expense on convertible debentures and acquisition financing fees[1]	**—**	18.2	**9.3**	57.6
Acquisition-related costs	**1.3**	2.4	**62.8**	12.0
Cash generated from sale of long-lived assets	**—**	—	**—**	(8.6)
Adjusted Funds from Operations	**$ 159.1**	$ 96.4	**$ 614.5**	$ 356.4

[1] Exclusive of deferred financing fees of $8.3 million.

For the three months ended December 31, 2017, Adjusted Funds from Operations totaled $159.1 million as compared to Adjusted Funds from Operations of $96.4 million for the same period in 2016, an increase of $62.7 million.

For the twelve months ended December 31, 2017 , Adjusted Funds from Operations totaled $614.5 million as compared to Adjusted Funds from Operations of $356.4 million for the same period in 2016, an increase of $258.1 million.

SUMMARY OF PROPERTY, PLANT, AND EQUIPMENT EXPENDITURES [1]

	Three Months Ended December 31		Twelve Months Ended December 31	
(all dollar amounts in $ millions)	2017	2016	2017	2016
Liberty Power Group:				
Maintenance	**$ 4.0**	$ 21.0	**$ 18.1**	$ 58.6
Investment in Capital Projects[1]	**17.1**	169.0	**592.7**	538.1
	$ 21.1	$ 190.0	**$ 610.8**	$ 596.7
Liberty Utilities Group:				
Rate Base Maintenance	**$ 58.4**	$ 27.0	**$ 222.1**	$ 102.7
Rate Base Acquisition	**—**	—	**2,764.4**	345.3
Rate Base Growth	**89.8**	101.0	**328.7**	163.4
	148.2	128.0	**3,315.2**	611.4
Total Capital Expenditures	**$ 169.3**	$ 318.0	**$ 3,926.0**	$ 1,208.1

[1] Includes expenditures on Property Plant & Equipment, equity-method investees, and acquisitions of operating entities that were jointly developed by the Company.

2017 Fourth Quarter Property Plant and Equipment Expenditures

During the three months ended December 31, 2017, the Liberty Power Group incurred capital expenditures of $21.1 million as compared to $190.0 million during the same period in 2016. The capital expenditures include the ongoing construction of the Great Bay Solar Project, additional investment into the Amherst Wind Project, and ongoing maintenance capital at existing operating sites. Capital expenditures in the same quarter last year included the purchase of approximately $75 million of turbine components ("Safe Harbor Turbines"), costs of rebuilding the Donnaconna Hydro Facility dam, and ongoing development costs related to the investment and build of the Deerfield Wind, Amherst Wind, and Great Bay Solar Projects.

During the three months ended December 31, 2017, the Liberty Utilities Group invested $148.2 million in capital expenditures as compared to $128.0 million during the same period in 2016. The Liberty Utilities Group's investment was primarily related to reliability enhancements, improvements and replenishment opportunities, and leak prone pipe replacements, leak repairs and pipeline corrosion protection initiatives relating to safety and reliability at the electric and gas systems. Capital expenditures in the same quarter last year included investments into the Luning Solar Facility and further development of Phase I of the North Lake Tahoe transmission project to upgrade the 650 Line (10 miles) which runs from Northstar to Kings Beach, California to 120kV.

2017 Annual Property Plant and Equipment Expenditures

During the twelve months ended December 31, 2017, the Liberty Power Group incurred capital expenditures of $610.8 million as compared to $596.7 million during the same period in 2016. The capital expenditures include the acquisition of the remaining outstanding interest in the Deerfield Wind Facility, completion of the Bakersfield II Solar Facility, upgrade of the Tinker Transmission Facility, and ongoing development costs related to the investment and construction of the Amherst Wind and Great Bay Solar Projects.

During the twelve months ended December 31, 2017, the Liberty Utilities Group invested $3.3 billion in capital expenditures as compared to $611.4 million during the same period in 2016. The increase in capital expenditures is primarily due to the Empire Acquisition in January 2017 (U.S. $2.4 billion) and completion of the Luning Solar Facility located in Mineral County, Nevada in February 2017 (U.S. $84.9 million). In the prior year, the Liberty Utilities Group completed the acquisition of the Park Water System in January 2016, further development of Phase I of the North Lake Tahoe transmission project, and reliability enhancements, improvements and replenishment opportunities at the utility systems served.

2018 Capital Investments

In 2018, the Company plans to spend between $1.2 billion and $1.4 billion on capital investment opportunities. Actual expenditures during the course of 2018 may vary due to timing of various project investments and the realized U.S. dollar exchange rate.

Expected 2018 capital investment ranges are as follows:

(all dollar amounts in $ millions)

Liberty Power Group:					
Maintenance	$	30.0	- $		40.0
Investment in Capital Projects		120.0	-		150.0
Total Liberty Power Group:	$	150.0	- $		190.0
Liberty Utilities Group:					
Rate Base Maintenance	$	210.0	- $		230.0
Rate Base Growth		140.0	-		180.0
Total Liberty Utilities Group:	$	350.0	- $		410.0
Investment in Atlantica[1]	$	700.0	$		800.0
Total 2018 Capital Investments	**$**	**1,200.0**	**- $**		**1,400.0**

[1] See *Major Highlights*

The Liberty Power Group intends to spend between $150.0 million - $190.0 million over the course of 2018 to develop or further invest in capital projects, primarily in relation to the final development of the Great Bay Solar and Amherst Island Wind Projects. Additionally, the Liberty Power Group plans to spend $30.0 million - $40.0 million on various operational solar, thermal, and wind assets to maintain safety, regulatory, and operational efficiencies.

The Liberty Utilities Group intends to spend between $350.0 million - $410.0 million over the course of 2018 in an effort to improve the reliability of the utility systems and broaden the technologies used to better serve its service areas. Projects

entail spending capital for structural improvements, specifically in relation to drilling and equipping aquifers, main replacements, and reservoir pumping stations.

LIQUIDITY AND CAPITAL RESERVES

APUC has revolving credit and letter of credit facilities available for Corporate, the Liberty Power Group, and the Liberty Utilities 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, 2017:

	As at December 31, 2017				As at Dec 31, 2016
(all dollar amounts in $ millions)	Corporate	Liberty Power	Liberty Utilities	Total	Total
Committed facilities	$ 165.0	$ 714.9	$ 501.8	**$ 1,381.7**	$ 773.8
Funds drawn on facilities	—	(44.8)	(16.3)	**(61.1)**	(242.9)
Letters of credit issued	(13.9)	(136.3)	(24.5)	**(174.7)**	(234.9)
Liquidity available under the facilities	**151.1**	**533.8**	**461.0**	**1,145.9**	296.0
Cash on hand				**54.6**	110.4
Total Liquidity and Capital Reserves	**$ 151.1**	**$ 533.8**	**$ 461.0**	**$ 1,200.5**	$ 406.4

As at December 31, 2017, the Company's $165.0 million senior unsecured revolving credit facility (the "Corporate Credit Facility") was undrawn and had $13.9 million of outstanding letters of credit. The facility matures on November 19, 2018 and is subject to customary covenants.

On December 21, 2017, the Company entered into a U.S. $600.0 million term credit facility with two Canadian banks maturing on December 21, 2018. The proceeds of the term credit facility provide the company with additional liquidity for general corporate purposes and acquisitions. On March 7, 2018 the company drew U.S. $600.0 million under this facility.

As at December 31, 2017, the Liberty Power Group's committed bank lines consisted of a U.S. $500.0 million senior unsecured syndicated revolving credit facility and a $87.6 million letter of credit facility (Cdn $50.0 million and U.S. $30.0 million). As at December 31, 2017, the group had drawn $44.8 million and had $136.3 million in outstanding letters of credit. The facilities mature on October 6, 2022 and October 30, 2018, respectively. Subsequent to year-end, on February 16, 2018, the Liberty Power Group increased availability under its revolving letter of credit facility to U.S. $200.0 million and extended the maturity to January 31, 2021. The expansion of both the revolving credit and letter of credit facility further increases the Liberty Power Group's ability to support the cash needs of its development portfolio.

As at December 31, 2017, the Liberty Utilities Group's committed bank lines consisted of a U.S. $200.0 million senior unsecured syndicated revolving credit facility at the holding company ("Liberty Credit Facility") and a U.S. $200.0 million revolving credit facility at Empire ("Empire Credit Facility"). The credit facilities mature on September 30, 2018 and October 20, 2019, respectively. The Empire Credit Facility is used primarily as a backstop to commercial paper issued by Empire. As at December 31, 2017, the Liberty Utilities Group had drawn a total of $16.3 million (U.S. $13.0 million) and had $24.5 million (U.S. $19.5 million) of outstanding letters of credit. Subsequent to year-end on February 23, 2018, the Liberty Utilities Group increased commitments under the Liberty Credit Facility to U.S. $500.0 million and extended the maturity to 2023. In conjunction with the increase to the Liberty Credit Facility, the Empire Credit Facility was canceled. The Liberty Credit Facility will now be used as a backstop for Empire's commercial paper program and as a source of liquidity for Empire as required.

On February 9, 2016, in connection with the Empire Acquisition, the Company obtained U.S. $1.6 billion in acquisition financing commitments ("Acquisition Facility") from a syndicate of banks. On December 30, 2016, the Company drew U.S. $1,336.4 million on the Acquisition Facility in connection with the closing of the Empire Acquisition. The Acquisition Facility was fully repaid in the first quarter of 2017 from proceeds received from the final installment payment, the Liberty Private Placement (discussed below) and general corporate funds.

Long Term Debt

On January 17, 2017, the Liberty Power Group issued $300.0 million of senior unsecured debentures bearing interest at 4.09% with a maturity date of February 17, 2027. The debentures were sold at a price of $99.929 per $100.00 principal amount. Concurrent with the offering, the Liberty Power Group entered into a cross currency swap, coterminous with the debentures, to economically convert the Canadian dollar denominated offering into U.S. dollars for an effective yield of 4.86%.

On March 24, 2017, the Liberty Utilities Group's financing entity issued U.S. $750.0 million of senior unsecured notes ("Liberty Private Placement") in the U.S. and Canada. The notes are of varying maturities from 3 to 30 years with a weighted average life of approximately 15 years and a weighted average coupon of 4.0%. In anticipation of the financing, Liberty Utilities had entered into forward contracts to lock in the underlying U.S. Treasury interest rates (see "*Interest Rate Risk*"). Considering the effect of the hedges, the effective weighted average rate paid by the Liberty Utilities Group is 3.6%. The proceeds of the offering were applied to repay the balance of the Acquisition Facility and other existing indebtedness.

As at December 31, 2017, the weighted average tenor of APUC's total long term debt is approximately 12 years with an average interest rate of 4.6%.

Convertible Unsecured Subordinated Debentures

In the first quarter of 2016, in connection with the Empire Acquisition, APUC and its direct wholly-owned subsidiary, Liberty Utilities (Canada) Corp., entered into an agreement with a syndicate of underwriters under which the underwriters agreed to buy, on a bought deal basis, $1.15 billion aggregate principal amount of 5.00% convertible unsecured subordinated debentures of APUC.

All Debentures were sold on an instalment basis at a price of $1,000 dollars per debenture, of which $333 dollars was paid on the closing of the Offering and the remaining $667 dollars was payable on a date set by APUC upon satisfaction of all conditions precedent to the closing of the Empire Acquisition (the "Final Instalment Date"), at which time each debenture was convertible to 94.3396 common shares of APUC and bears an interest rate of 0% thereafter.

The final instalment date was established as February 2, 2017, at which time APUC received the final instalment payment. The proceeds were used to repay a portion of the Acquisition Facility. As at March 6, approximately 99.9% of the Debentures have been converted into common shares of APUC, with APUC issuing approximately 108,384,716 common shares as a result of the conversion.

Credit Ratings

APUC has a long term consolidated corporate credit rating of BBB (flat) from Standard & Poor's ("S&P") and a BBB (low) rating from DBRS Limited ("DBRS"). Algonquin Power Co ("APCo"), the parent company for the Liberty Power Group, has a BBB (flat) issuer rating from S&P and BBB (low) issuer rating from DBRS. Liberty Utilities Finance GP1 ("Liberty Finance"), a special purpose financing entity of Liberty Utilities Co., the parent company for the Liberty Utilities Group, has a BBB (high) issuer rating from DBRS. Empire has a BBB rating from S&P and a Baa1 rating from Moody's Investors Service, Inc. ("Moody's").

Contractual Obligations

Information concerning contractual obligations as of December 31, 2017 is shown below:

(all dollar amounts in $ millions)	Total	Due less than 1 year	Due 1 to 3 years	Due 4 to 5 years	Due after 5 years
Principal repayments on debt obligations[1]	**$ 3,826.1**	$ 279.7	$ 570.1	$ 645.0	$ 2,331.3
Convertible debentures	**1.2**	—	—	—	1.2
Advances in aid of construction	**78.6**	1.5	—	—	77.1
Interest on long-term debt obligations	**2,006.2**	172.7	307.5	250.8	1,275.2
Purchase obligations	**501.9**	501.9	—	—	—
Environmental obligations	**72.0**	7.8	18.9	5.4	39.9
Derivative financial instruments:					
Cross currency swap	**72.0**	4.4	8.1	64.7	(5.2)
Interest rate swap	**10.6**	10.6	—	—	—
Currency forward	**0.4**	0.4	—	—	—
Energy derivative and commodity contracts	**3.4**	2.3	1.0	—	0.1
Purchased power	**527.4**	74.0	98.3	100.7	254.4
Gas delivery, service and supply agreements	**369.2**	91.4	118.7	61.6	97.5
Service agreements	**673.9**	47.7	95.7	95.4	435.1
Capital projects	**58.3**	41.1	17.1	0.1	—
Operating leases	**270.0**	9.6	17.3	18.1	225.0
Other obligations	**155.3**	45.0	—	—	110.3
Total Obligations	**$ 8,626.5**	**$ 1,290.1**	**$ 1,252.7**	**$ 1,241.8**	**$ 4,841.9**

[1] Exclusive of deferred financing costs, bond premium/discount, fair value adjustments at the time of issuance or acquisition.

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 December 31, 2017, APUC had 431,765,935 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.

On November 10, 2017, APUC announced that it closed a bought deal offering announced on November 1, 2017, including the exercise in full of the underwriters' over-allotment option. As a result a total of 43,470,000 common shares of APUC were sold at a price of $13.25 per share for gross proceeds of approximately $576.0 million.

Net proceeds of the offering are expected to be used, in part, to finance APUC's acquisition of a 25% ownership stake in Atlantica from Abengoa and for general corporate purposes.

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, 2017, APUC had outstanding:

- 4,800,000 cumulative rate reset Series A preferred shares, yielding 4.5% annually for the initial six-year period ending on December 31, 2018;
- 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 5.0% annually for the initial five year period ending on March 31, 2019.

APUC has a shareholder dividend reinvestment plan (the “Reinvestment Plan”) for registered holders of common shares of APUC. As at December 31, 2017, 94,049,616 common shares representing approximately 22% of total common shares outstanding had been registered with the Reinvestment Plan. During the year ended December 31, 2017, 3,905,848 common

shares were issued under the Reinvestment Plan, and subsequent to year-end, on January 12, 2018, an additional 1,063,572 common shares were issued under the Reinvestment Plan.

SHARE-BASED COMPENSATION PLANS

For the twelve months ended December 31, 2017, APUC recorded $10.8 million in total share-based compensation expense as compared to $5.7 million for the same period in 2016. There is no tax benefit associated with the share-based compensation expense. 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, 2017, total unrecognized compensation costs related to non-vested options and share unit awards were $2.8 million and $8.5 million, respectively, and are expected to be recognized over a period of 1.61 and 1.84 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 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, 2017, the Company granted 2,328,343 options to executives of the Company. The options allow for the purchase of common shares at a weighted average price of $12.82, the market price of the underlying common share at the date of grant. In March 2017, executives of the Company exercised 1,469,362 stock options at a weighted average exercise price of $7.81 in exchange for common shares issued from treasury and 165,139 options were settled at their cash value as payment for tax withholdings related to the exercise of the options.

As at December 31, 2017, a total of 6,738,856 options are issued and outstanding under the stock option plan.

Performance Share Units

APUC issues performance share units ("PSUs") to certain members of management as part of APUC's long-term incentive program. During the twelve months ended December 31, 2017, the Company granted (including dividends and performance adjustments) 811,974 PSUs to executives and employees of the Company. During the year, the Company settled 374,973 PSUs, of which 183,035 PSUs were exchanged for common shares issued from treasury and 191,938 PSUs were settled at their cash value as payment for tax withholdings related to the settlement of the PSUs. Additionally, during 2017, a total of 60,961 PSUs were forfeited.

As at December 31, 2017, a total of 955,028 PSUs are granted and outstanding under the PSU plan.

Directors Deferred Share Units

APUC has a Directors' Deferred Share Unit Plan. Under the plan, non-employee directors of APUC receive 50% 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, 2017, the Company issued 69,243 DSUs (including DSUs in lieu of dividends) to the directors of the Company.

As at December 31, 2017, a total of 293,906 DSUs had been granted under the DSU plan.

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, 2017, the Company issued 283,523 common shares to employees under the ESPP.

As at December 31, 2017, a total of 779,553 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 cash reserves on hand 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

Emera Inc.

An executive at Emera Inc. ("Emera") was a member of the Board of APUC until June 8, 2017. The Energy Services Business sold electricity to Maine Public Service Company, and Bangor Hydro, both of which are subsidiaries of Emera. The portion considered related party transactions during 2017 amounts to U.S. $4.4 million as compared to U.S. $10.2 million during the same period in 2016. The Liberty Utilities Group purchased natural gas from Emera for its gas utility customers. The portion considered related party transactions during 2017 amounts to U.S. $1.0 million as compared to U.S. $3.9 million during the same period in 2016. Both the sale of electricity to Emera and the purchase of natural gas from Emera followed a public tender process, the results of which were approved by the regulator in the relevant jurisdiction.

In 2016, a subsidiary of the Company and Emera Utility Services Inc. entered into a design, engineering, supply, and construction agreement for the Tinker transmission upgrade project. The transmission upgrade was placed in service in the second quarter of 2017, with the final completion of the contract work in the fourth quarter of 2017. The total cost of the contract was $9.5 million. The contract followed a market based request for proposal process. On October 14, 2016, APUC paid $0.7 million to Emera as reimbursement for professional services incurred and accrued in 2014.

There was U.S. $1.5 million included in accruals in 2017 as compared to U.S. $0.8 million during the same period in 2016 related to these transactions.

Equity-method investments

The Company provides administrative services to its equity-method investees and is reimbursed for incurred costs. To that effect, the Company charged its equity-method investees $6.0 million in 2017 as compared to $3.3 million during the same period in 2016.

Trafalgar

In 2016, the Company received U.S. $10.1 million in proceeds from the settlement of the Trafalgar matter and paid U.S. $2.9 million to an entity partially and indirectly owned by Senior Executives as its proportionate share. The gain to APUC, net of legal and other liabilities, of approximately U.S. $6.6 million was recorded in 2016.

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. 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. The description of risks below does not include all possible risks.

An enterprise risk management, or "ERM", framework is embedded across the organization that systematically and broadly identifies, assesses, and mitigates 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 ERM policy details the risk management processes, risk appetite, and risk governance structure which clearly establishes accountabilities for managing risk across the organization.

As part of the risk management processes, risk registers have been developed across the organization through ongoing risk identification and risk assessment exercises facilitated by the Corporation's internal ERM team. Risk information is sourced throughout the organization using a variety of methods including risk identification interviews and workshops, as well as the Corporation's "Risk Insights" program, which provides all employees with a mechanism to communicate risks and opportunities at any time. 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 on a quarterly basis.

Risks are evaluated consistently across the organization using a common 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 development and execution of risk treatment plans for the organization's top risks are actively monitored by the Company's senior leadership team and Board of Directors. The Corporation's internal audit team is responsible for conducting audits to validate and test the effectiveness of controls for key risks. Audit findings are discussed with business owners and reported to the Audit Committee of the Board of Directors on a quarterly basis. All material changes to exposures, controls or treatment plans of key risks are reported to the ERM team, Enterprise Risk Management Council, the Corporate Governance and Risk Committees, and the Board of Directors of the Corporation for consideration.

The Corporation's ERM framework follows the guidance of ISO 31000:2009. The Board oversees management to ensure the risk governance structure and risk management processes are robust, and that the Corporation's risk appetite is thoroughly considered in decision-making across the organization

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' business risks is set out in the Company's most recent AIF available on SEDAR.

Treasury Risk Management

Downgrade in the Company's Credit Rating Risk

APUC has a long term consolidated corporate credit rating of BBB (flat) from S&P and a BBB (low) rating from DBRS. Algonquin Power Co ("APCo"), the parent company for the Liberty Power Group, has a BBB (flat) issuer rating from S&P and BBB (low) issuer rating from DBRS. Liberty Utilities Finance GP1 ("Liberty Finance"), a special purpose financing entity of Liberty Utilities Co., the parent company for the Liberty Utilities Group, has a BBB (high) issuer rating from DBRS. Empire has a BBB rating from S&P and a Baa1 rating from Moody's.

The ratings indicate the agencies' assessment of APUC's ability to pay the interest and principal of debt securities it issues. 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. If any of APUC's ratings fall below investment grade (investment grade is defined as BBB- or above for S&P and BBB low or above for DBRS), APUC's ability to issue short-term debt or other securities or to market those securities would be impaired 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.

Capital Markets and Liquidity Risk

As of December 31, 2017, the Company had approximately $3,864.5 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 the costs of planned 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 favorable terms may be affected by the Company's financial and operational performance, and 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 degree of 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 on its common shares; 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 that have less debt; 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 favorable than the current terms, 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 future 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, 2017, 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 no amounts outstanding as at December 31, 2017. As a result, a 100 basis point change in the variable rate charged would not impact interest expense;
- The Liberty Power Group's revolving credit facility is subject to a variable interest rate and had $44.8 million outstanding as at December 31, 2017. A 100 basis point change in the variable rate charged would impact interest expense by $0.4 million annually;
- The Liberty Utilities Group's revolving credit facilities are subject to a variable interest rate and had $16.3 million outstanding as at December 31, 2017. As a result, a 100 basis point change in the variable rate charged would impact interest expense by $0.2 million annually.
- The Liberty Utilities Group's commercial paper program is subject to a variable interest rate and had $7.0 million (U.S. $5.6 million) outstanding at December 31, 2017. As a result, a 100 basis point change in the variable rate charged would impact interest expense by $0.1 million annually.
- The Corporate Term Facility is subject to a variable interest rate and had $169.4 million (U.S. $135.0 million) outstanding as at December 31, 2017. A 100 basis point change in the variable rate charged would impact interest expense by $1.7 million annually;

To mitigate financing risk, from time to time APUC may seek to fix interest rates on expected future financings. In the fourth quarter of 2014, the Liberty Power Group entered into a hedge to fix the underlying interest rate for the anticipated refinancing of its $135.0 million bond maturing in July 2018. Hedge accounting treatment applies to this transaction. Consequently, changes in fair value, to the extent deemed effective, are being recorded in Other Comprehensive Income.

Foreign Currency Risk

Currency fluctuations may affect the Canadian dollar equivalent cash flows that APUC realizes from its consolidated operations because a significant portion of the Company's revenues are generated through APUC subsidiary businesses which sell electricity or provide utility services in the United States and receive proceeds from such sales in U.S. dollars. Such APUC businesses also incur costs in U.S. dollars. At the current exchange rate, approximately 93% of Adjusted EBITDA in 2017 and 93% of cash flow from operations is generated in U.S. dollars.

APUC estimates that, on an unhedged basis, a $0.10 increase in the strength of the U.S. dollar relative to the Canadian dollar would result in a net impact on U.S. operations of approximately $82.3 million ($0.22 per share) on an annual basis. In light of the currency profile of its operations, APUC pays its dividend in U.S. dollars. APUC further manages currency risk through the matching of U.S. dollar denominated long term debt for the debt requirements of its U.S. operations, thereby creating a natural hedge for the operating profit vis a vis financing costs.

APUC may enter into derivative contracts to hedge all or a portion of currency exchange rate exposure that is transactional in nature and where a natural economic hedge does not exist. To the extent that the Company does enter into currency hedges, the Company may not realize the full benefits of favorable exchange rate movement, and is subject to risks that the counterparty to the hedging contracts may prove unable or unwilling to perform their obligations under the contracts.

Effective the first quarter of 2018, APUC will begin to report its results in U.S. dollars.

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 APUC does business could adversely affect the Company’s results from operations, our return 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 our results of operations and financial position.

Development by the Liberty Power Group of renewable power generation facilities in the United States depends in part on federal tax credits and other tax incentives. Although these incentives have been extended on multiple occasions, the most recent extension provides for a multi-year step-down. While recently enacted U.S. tax reform legislation did not make any changes to the multi-year step-down, there can be no assurance that there will not be further changes in the future. If these incentives are reduced or APUC is unable to complete construction on anticipated schedules, the reduced incentives may be insufficient to support continued development and construction of renewable power facilities in the United States or may result in substantially reduced benefits from facilities that APUC is committed to complete. In addition, the Liberty Power Group 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 Company 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 Company (See *U.S. Tax Reform*).

Credit/Counterparty Risk

APUC and its subsidiaries, through its long term power purchase contracts, 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.

Liberty Power Group's revenues are approximately 15% of total Company revenues. Approximately 94% of the Liberty Power 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 following chart sets out the Liberty Power Group's customers representing greater than 5% of total Liberty Power Group revenues and their credit ratings:

Counterparty	Credit Rating [1]		Approximate Annual Revenues	Percentage of Liberty Power Group Revenue
PJM Interconnection LLC	Aa2	$	31.8	11.2%
Manitoba Hydro	Aa2		30.3	10.7%
Hydro Quebec	Aa2		29.1	10.3%
Commonwealth Edison	A3		26.4	9.3%
Xcel Energy	A3		24.2	8.6%
Pacific Gas and Electric Company	A3		24.1	8.5%
Wolverine Power Supply	A		23.5	8.3%
Ontario Electricity Financial Corporation	Aa2		22.9	8.1%
Electric Reliability Council of Texas (ERCOT)	Aa3		16.7	5.9%
Connecticut Light and Power	Baa1		16.2	5.7%
Total		**$**	**245.2**	

[1] Ratings by DBRS, Moody's, or S&P.

The remaining revenue of the Company is primarily earned by the Liberty Utilities Group. In this regard, the credit risk attributed to the Liberty Utilities Group's accounts receivable balances at the water and wastewater distribution systems total U.S. $10.4 million which is spread over approximately 160,000 connections, resulting in an average outstanding balance of approximately U.S. $70 dollars per connection.

The natural gas distribution systems accounts receivable balances related to the natural gas utilities total U.S. $21.1 million, while electric distribution systems accounts receivable balances related to the electric utilities total U.S. $99.9 million. The natural gas and electrical utilities both derive over 84% of their revenue from residential customers.

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 fully compensated through bad debt reserves approved by the applicable utility regulator. If a customer under a long-term power purchase agreement with the Liberty Power Group is unable to perform, the Liberty Power 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 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 Liberty Power Group predominantly enters into long term PPAs for its generation assets and hence is not exposed to market risk for this portion of its portfolio. Where a generating asset is not covered by a power purchase contract, the Liberty Power 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 Liberty Power 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 Liberty Power 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 Liberty Power Group along with residual exposures to the market are detailed below:

The July 1, 2012 acquisition of the Sandy Ridge Wind Facility included a financial hedge, which commenced on January 1, 2013, for a 10 year period. The financial hedge is structured to hedge 72% of the Sandy Ridge Wind Facility's expected production volume against exposure to PJM Western Hub current spot market rates. The annual unhedged production based on long term projected averages is approximately 44,000 MW-hrs annually. Therefore, each U.S. $10 per MW-hr change in the market price would result in a change in revenue of approximately U.S. $0.4 million for the year.

A second hedge for the Sandy Ridge Wind Facility will commence on January 1, 2023, for a one year period. The financial hedge is structured to hedge 73% of the Sandy Ridge Wind Facility's expected production volume against exposure to PJM Western Hub current spot market rates. The annual unhedged production based on long term projected averages is approximately 42,000 MW-hrs annually.

The December 10, 2012 acquisition of the Senate Wind Facility included a physical hedge, which commenced on January 1, 2013, for a 15 year period. The physical hedge is structured to hedge 64% of the Senate Wind Facility's expected production volume against exposure to ERCOT North Zone current spot market rates. The annual unhedged production based on long term projected averages is approximately 188,000 MW-hrs annually. Therefore, each U.S. $10 per MW-hr change in the market price would result in a change in revenue of approximately U.S. $2.0 million for the year.

The December 10, 2012 acquisition of the Minonk Wind Facility included a financial hedge, which commenced on January 1, 2013, for a 10 year period. The financial hedge is structured to hedge 73% of the Minonk Wind Facility's expected production volume against exposure to PJM Northern Illinois Hub current spot market rates. The annual unhedged production based on long term projected averages is approximately 186,000 MW-hrs annually. Therefore, each U.S. $10 per MW-hr change in market prices would result in a change in revenue of approximately U.S. $2.0 million for the year.

A second hedge for the Minonk Wind Facility will commence on January 1, 2023, for a one year period. The financial hedge is structured to hedge 72% of the Minonk Wind Facility's expected production volume against exposure to PJM Northern Illinois Hub current spot market rates. The annual unhedged production based on long term projected averages is approximately 189,000 MW-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 Liberty Power Group enters into short-term derivative contracts (with terms of one to three months) to further mitigate market price risk exposure due to production variability. As at December 31, 2017, the Liberty Power Group had entered into hedges with a cumulative notional quantity of 7,080 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 U.S. $10 per MW-hr change in market prices would result in a change in revenue of approximately U.S. $0.5 million for the year.

Commodity Price Risk

The Liberty Power Group's exposure to commodity prices is primarily limited to exposure to natural gas price risk. The Liberty Utilities Group is exposed to energy and natural gas price risks at its electric and natural gas systems. In this regard, a discussion of this risk is set out as follows:

- 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 $0.2 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 $0.1 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 181,000 MW-hrs in fiscal 2018, of which 170,000 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 37,000 MW-hrs of its energy requirements at the ISO-NE spot rates to supplement self-generated energy should the Maritime region be able to reach the estimated 181,000 MW-hrs. The risk associated with the expected market purchases of 37,000 MW-hrs is mitigated through the use of short-term financial energy hedge contracts which cover approximately 20% of the Maritime region's anticipated purchases during the price-volatile winter months at an average rate of approximately $86 per MW-hr. For the amount of anticipated purchases not covered by hedge contracts, each U.S. $10.00 change per MW-hr in the market prices in ISO-NE would result in a change in expense of $0.3 million on an annualized basis.

The Calpeco Electric System provides electric service to the Lake Tahoe California basin and surrounding areas at rates approved by the 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 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 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 14% 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 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.

The Georgia (Peach State) Gas System purchases pipeline capacity, storage and commodity from a variety of counterparties, and files with the Georgia 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.

Empire 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. Empire met approximately 58% of its 2017 generation fuel supply need through coal. Approximately 97% of its 2017 coal supply was Western coal. Empire has contracts and binding proposals to supply a portion of the fuel for its coal plants through 2018. These contracts and inventory on hand satisfy approximately 56% of anticipated fuel requirements for 2018 for the Asbury Coal Facility.

Empire is exposed to changes in market prices for natural gas needed to run combustion turbine generators. Empire's natural gas procurement program is designed to manage costs to avoid volatile natural gas prices. Empire periodically enters into physical forward and financial derivative contracts with counterparties to meet future natural gas requirements by locking in prices (with respect to predetermined percentages of our expected future natural gas needs) in an attempt to lessen the volatility in fuel expenditures and improve predictability. Gains and losses associated with the hedging program are passed through to customers in the fuel adjustment clause and PGA filings and are embedded in the approved rates in such filings.

OPERATIONAL RISK MANAGEMENT

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, interruption in supply chain and expenses related to claims or clean-up to adhere to environmental and safety standards.

The Liberty Power 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 Liberty Power 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 Liberty Power 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 Liberty Power 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.

The Liberty Utilities 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 Liberty Utilities 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 Liberty Utilities 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.

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 Liberty Power Group hydroelectric facilities, water rights are generally owned by governments that reserve the right to control water levels, which may affect revenue.

The Liberty Utilities Group's facilities are subject to rate setting by state regulatory agencies. The Liberty Utilities Group operates in 12 different states and therefore is subject to regulation from 12 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 Liberty Utilities 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 Liberty Utilities 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 will have a significant impact on the financial operations and regulatory revenue requirements of most public utilities, including the Liberty Utilities Group. The Liberty Utilities Group is working with stakeholders to understand the full implications and impact of the new law. Liberty believes that customers will be best served by dealing with Tax Reform within the context of a full regulatory rate case, where all factors that comprise rates can be considered.

Condemnation Expropriation Proceedings

The Liberty Utilities 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.

Mountain Water Condemnation Proceedings

On May 6, 2014, the City of Missoula, Montana filed a lawsuit against Mountain Water Company and its prior indirect owner Carlyle Infrastructure Partners, L.P. ("Carlyle"), seeking to condemn the assets of Mountain Water. The case went to trial on the right to take or "necessity" phase in March, 2015. The District Court issued a Preliminary Order of Condemnation on June 15, 2015, finding that the City had established the right to take the assets of Mountain Water. Mountain Water filed an appeal with the Montana Supreme Court. The case then proceeded to a trial on valuation before three Commissioners. On November 17, 2015, the Commissioners issued a report finding that the "fair market value" of the condemned property as of May 6, 2014 was U.S. $88.6 million. On August 2, 2016, the Supreme Court of Montana upheld the District Court's decision, permitting the City of Missoula to proceed with the condemnation of Mountain Water's assets.

On December 22, 2015, certain developers filed a lawsuit in Montana District Court against the City of Missoula and Mountain Water seeking resolution of claims to a portion of the condemnation award on the basis that certain of the assets being condemned had been funded by such parties. On February 21, 2017, the court in that case recognized an equitable lien on such assets in favor of the developers and ordered that a portion of the condemnation award, if and when paid, be paid by the City of Missoula to the court for direct payment to the developers.

On or about June 5, 2017, Mountain Water, Liberty Utilities Co. and the City of Missoula entered into a Settlement Agreement and Release of Claims, resolving certain issues in the event that the City acquired possession of Mountain Water's assets, and contingent upon settlement of the developer lawsuit. The settlement agreement was approved by the condemnation court in hearings on June 15 and June 22, 2017, and a final order of condemnation was issued on June 22, 2017. The developer lawsuit was dismissed on June 30, 2017. On June 22, 2017, the City of Missoula paid the condemnation judgment, including amounts owed to Mountain Water and amounts required to be paid to the developers. The City of Missoula took possession of Mountain Water's assets on that date. Carlyle and Mountain Water have appealed certain elements of the final order of condemnation including, among other issues, recovery of post-summons interest and attorney's fees.

Apple Valley Condemnation Proceedings

On January 7, 2016, the Town of Apple Valley filed a lawsuit seeking to condemn the utility assets of Liberty Utilities (Apple Valley Ranchos Water) Corp. The Town seeks to condemn the utility assets of Apple Valley and to require a determination of fair market value. In the first phase of the case, the Court will determine the necessity of the taking by the Town. If the Court determines that necessity has been established, in a second phase, a jury will determine the fair market value of the assets being condemned. The condemnation case is currently proceeding in discovery. Resolution of the condemnation proceedings is expected to take two to three years. The Court has been briefed on a related California Environmental Quality Act ("CEQA") lawsuit (challenging the Town's compliance with CEQA in connection with the proposed condemnation) and heard oral argument in December 2017. The Court issued the CEQA decision on February 9, 2018 and denied Liberty Apple Valley's CEQA claim. As a result, the condemnation case will proceed. The Court has set a scheduling conference for the condemnation case on March 6, 2018 to potentially set a trial date on the first phase of the condemnation action.

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 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.

Joint Venture Investment Risk

Certain development and operating entities that the Company has interest in are jointly owned with third parties. The Company may not have the sole discretion or ability to affect the management or operations at such facilities and thereby may not be able to make determinations on how to manage these facilities in light of changing economic circumstances. A divergence in the interests of the Company and the co-owners could negatively impact the realization of the Company's investment in the joint venture business, which may have a disproportionate economic impact relative to the Company's investment.

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.

The Liberty Utilities Group's facilities are operated with the assumption that their services will be required in perpetuity and there are no contractual decommissioning requirements. In order to remain in compliance with the applicable regulatory bodies, the Liberty Utilities Group has regular programs at each facility to ensure its equipment is properly maintained and replaced on a cyclical basis. These costs can generally be included in the facility's rate base and thus the Liberty Utilities Group expects to be allowed to earn a return on such investment.

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 of wind facilities upon termination of land leases; (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

Liberty Power Group

The Liberty Power 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 Liberty Power 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 Liberty Power 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.

Liberty Utilities Group

The Liberty Utilities 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 Liberty Utilities Group's demand for energy from its electric distribution systems is primarily affected by weather conditions and conservation initiatives. The Liberty Utilities 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 Liberty Utilities 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 case proceedings. While not all regulatory jurisdictions have approved mechanisms to mitigate demand fluctuations, to date, the Liberty Utilities Group has successfully obtained regulatory approval to implement such decoupling mechanisms in 4 of 12 states representing approximately 25% of customers. 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. The Liberty Utilities Group is presently seeking weather related decoupling mechanism for its utilities in Missouri and New Hampshire.

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.

Litigation Risks and Other Contingencies

APUC and certain of its subsidiaries are involved in various litigations, 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.

See further discussion of claims made by or against APUC or its subsidiaries in *Regulatory Risk*.

Cybersecurity 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. Should a material breach occur the Company may not be able to recover all costs and losses through insurance, legal or regulatory processes.

The Company mitigates these risks by maintaining a cybersecurity program that is overseen by the Board of Directors, and executed by a cross functional management team. The program is intended to provide adequate controls for the appropriate protection of critical business systems. These controls have been put into place to mitigate potential risks, and to improve the organization’s capability to respond and recover from any potential cyber incident.

Energy Consumption and Advancement in Technologies Risk

The Liberty Utilities 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 Liberty Utilities 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 Liberty Utilities 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. However, there are certain elements of the Liberty Utilities 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 Liberty Utilities 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, 2017:

(all dollar amounts in $ millions except per share information)	1st Quarter 2017	2nd Quarter 2017	3rd Quarter 2017	4th Quarter 2017
Revenue	$ 557.9	$ 453.2	$ 443.3	$ 523.4
Net earnings attributable to shareholders	26.0	47.7	59.4	60.0
Net earnings per share	0.07	0.12	0.15	0.14
Adjusted Net Earnings	88.1	53.3	64.9	85.9
Adjusted Net Earnings per share	0.25	0.13	0.16	0.20
Adjusted EBITDA	254.8	197.6	197.5	233.4
Total assets	10,880.7	10,528.6	10,306.7	10,533.6
Long term debt[1]	4,773.6	4,418.0	4,435.1	3,864.5
Dividend declared per common share	$ 0.15	$ 0.16	$ 0.15	$ 0.15

	1st Quarter 2016	2nd Quarter 2016	3rd Quarter 2016	4th Quarter 2016
Revenue	$ 341.7	$ 222.8	$ 221.3	$ 310.2
Net earnings attributable to shareholders	42.0	24.8	17.7	46.3
Net earnings per share	0.15	0.08	0.06	0.16
Adjusted Net Earnings	56.1	30.9	26.6	51.4
Adjusted Net Earnings per share	0.21	0.11	0.09	0.18
Adjusted EBITDA	147.9	99.2	91.4	138.3
Total assets	5,615.5	5,555.0	6,020.8	8,249.5
Long term debt[1]	2,214.5	2,199.9	2,380.8	4,272.0
Dividend declared per common share	$ 0.13	$ 0.14	$ 0.14	$ 0.14

[1] 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 $221.3 million and $557.9 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 U.S. operations.

Quarterly net earnings attributable to shareholders have fluctuated between $ 17.7 million and $60 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.

DISCLOSURE CONTROLS AND PROCEDURES

APUC's management carried out an evaluation as of December 31, 2017, 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, 2017, 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 CFO, 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. 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, 2017, the Company acquired Empire. Management is in the process of evaluating the existing controls and procedures of Empire and integrating financial reporting and controls for Empire into the Company's internal control over financial reporting. The financial information for this acquisition is included in this MD&A and in *note 3* to the consolidated financial statements. As permitted by National Instrument 52-109 and the SEC, due to the complexity associated with assessing internal controls during integration efforts, the Company excluded this acquisition from its assessment of the effectiveness of the Company's internal controls over financial reporting (representing approximately 30% of our total assets as of December 31, 2017 and approximately 41% of our revenues and 35% of our net income for the year ended December 31, 2017).

Management assessed the effectiveness of the Company's internal control over financial reporting as of December 31, 2017, 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 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, 2017 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, 2017 , there has been no change in the Company's internal control over financial reporting that has materially affected, or is reasonably likely to materially affect, the Company's internal control over financial reporting. The Company continues to implement its internal control structure over the operations of the acquired business discussed above.

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 estimates relate to the 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* to the 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.

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.

A recoverability analysis was performed in 2017 for wind generating assets operating without a PPA and in 2016 for wind and small hydro generating assets without a PPA. No impairment provision was required in 2017 or 2016. A quantitative assessment of goodwill performed as at September 30, 2014 concluded that the fair value of each reporting unit substantially exceeded their carrying value. In 2017 and 2016, Management assessed qualitative and quantitative factors for each of the reporting units that were allocated goodwill. No goodwill impairment provision was required.

Measurement of Deferred Taxes

On December 22, 2017, the U.S. government enacted the Tax Cuts and Jobs Act (the "Act"). The Act made broad and complex changes to the U.S. tax code which impacted 2017 including, but not limited to, reducing the U.S. federal corporate tax rate from 35% to 21% and introducing 100% expensing for certain capital expenditures, excluding regulated utilities, made after September 27, 2017. Management's judgment is required to measure the deferred taxes assets and liabilities at the enactment date based on these changes. Where requirements of the implementation of the new Act are incomplete, management uses judgments and assumptions to calculate a reasonable provisional amount to include in the Company's financial statements.

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. Management's assessment has been impacted by the tax reform discussed above.

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 Liberty Utilities 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.

The Financial Accounting Standards Board ("FASB") issued a revenue recognition standard codified as ASC 606, Revenue from Contracts with Customers. The Company expects the adoption of Topic 606 will have an immaterial impact on the consolidated financial statements and the pattern of revenue recognition. The Company intends to adopt the new revenue recognition standard using the modified retrospective method effective January 1, 2018.

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-2017) recently released by the Society of Actuaries adjusted to reflect the 2017 Social Security Administration ultimate improvement rates.

The FASB issued ASU 2017-07 Compensation—Retirement Benefits (Topic 715): Improving the Presentation of Net Periodic Pension Cost and Net Periodic Post-retirement Benefit Cost, for reporting of defined benefit pension cost and post-retirement benefit cost ("net benefit cost") in the financial statements. The Company will adopt this guidance effective January 1, 2018. Following the effective date of this Accounting Standards Update ("ASU"), the Company expects its regulated operations to only capitalize the service costs component and therefore no regulatory to U.S. GAAP reporting differences are anticipated. The Company intends to apply the practical expedient for retrospective application on the statement of operations.

Sensitivities

The sensitivities of key assumptions used in measuring accrued benefit obligations and benefit plan cost for 2017 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.

	2017 Pension Plans		2017 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	(65.6)	(4.4)	(31.5)	(1.9)
1% decrease	81.1	6.7	39.7	2.1
Future compensation rate				
1% increase	0.2	1.5	—	—
1% decrease	(0.2)	(1.3)	—	—
Expected return on plan assets				
1% increase	—	(4.5)	—	(1.4)
1% decrease	—	4.5	—	1.4
Life expectancy				
10% increase	38.0	3.3	19.7	1.6
10% decrease	(39.9)	(2.8)	(18.8)	(1.8)
Health care trend				
1% increase	—	—	38.0	4.3
1% decrease	—	—	(30.1)	(3.3)

Business Combinations

The Company has completed a number of business acquisitions 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 and on the APUC website at www.AlgonquinPowerandUtilities.com.

Consent of Independent Registered Public Accounting Firm

We consent to the reference to our Firm under the caption “Interest of Experts” and to the use in this Annual Report on Form 40-F filed with the United States Securities and Exchange Commission of our reports dated March 7, 2018, with respect to the consolidated balance sheets of Algonquin Power and Utilities Corp. (the “Company”) as at December 31, 2017 and 2016, and the consolidated statements of operations, comprehensive income/(loss), equity, and cash flows for each of the years in the two-year period ended December 31, 2017, and the effectiveness of internal control over financial reporting of the Company as at December 31, 2017.

We also consent to the incorporation by reference of our reports dated March 7, 2018 in the Registration Statements on Form S-8 (No. 333-177418), Form S-8 (File No. 333-213650), Form S-8 (File No. 333-213648), Form S-8 (File No. 333-218810), Form F-10 (No. 333-216616) and Form F-3D (No. 333-220059), with respect to the consolidated balance sheets of the Company as at December 31, 2017 and 2016, 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, 2017, and the effectiveness of internal control over financial reporting of the Company as at December 31, 2017.

/s/ “Ernst & Young LLP”

Toronto, Canada Chartered Professional Accountants,
March 7, 2018 Licensed Public Accountants

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: March 7, 2018

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: March 7, 2018

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, 2017 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: March 7, 2018

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, 2017 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: March 7, 2018

By: /s/ David Bronicheski
Name: David Bronicheski
Title: Chief Financial Officer