ALGONQUIN
Power & Utilities Corp.

ANNUAL REPORT

30 Years of Innovation and Growth

2018

CORPORATE PROFILE

Algonquin Power & Utilities Corp. ("Algonquin") is focused on providing clean, sustainable utility services to its nearly 800,000 North American customers, while delivering reliable earnings, cash flow, and dividend growth via operational excellence, strategic growth, and accretive acquisitions. Through its two business groups – Liberty Power and Liberty Utilities – Algonquin owns and operates a diversified portfolio of North American rate-regulated and non-regulated electricity, natural gas, and water utility businesses.

At Algonquin, we operate, develop and acquire long-lived, sustainable assets that are built for the long-term. Since our inception in 1988, we have grown to over 70 power generation facilities and utilities in Canada and the United States supported by more than 2,200 skilled and motivated employees who play a vital role in our success. Algonquin is also active in international infrastructure development and operations through its AAGES joint venture and its 41.5% equity interest in Atlantica Yield plc (NASDAQ: AY).

With our strong, diversified and growing presence in communities across the U.S., Canada, and internationally, we are continually demonstrating our commitment to thinking globally and acting locally.

Algonquin Power & Utilities Corp.

AlgonquinPowerandUtilities.com TSX/NYSE: **AQN**

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: expected future growth and results of operations; ongoing and planned acquisitions, projects and initiatives, expectations regarding international developments and operations; expectations and plans with respect to current and planned capital projects; and expectations regarding the future growth and results of operations of Atlantica Yield plc. Readers are advised that all forward-looking information in this document is provided subject to the cautionary statement regarding forward-looking information, which is found in Management's Discussion & Analysis section of this Annual Report beginning at page 1.

All monetary amounts are in thousands of U.S. dollars, except where otherwise noted.

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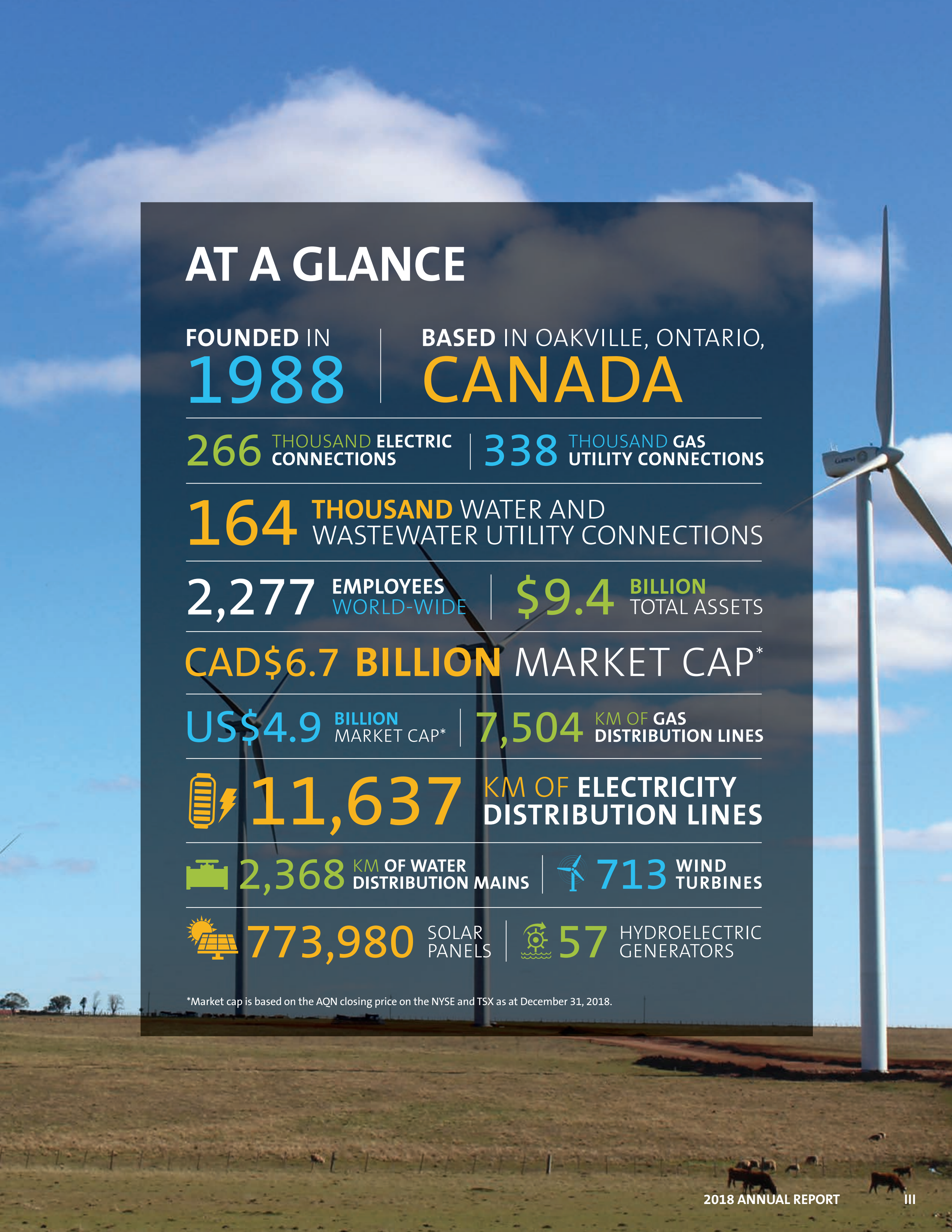


AT A GLANCE

FOUNDED IN **1988**

BASED IN OAKVILLE, ONTARIO, **CANADA**

266 THOUSAND **ELECTRIC CONNECTIONS**

338 THOUSAND **GAS UTILITY CONNECTIONS**

164 THOUSAND WATER AND WASTEWATER UTILITY CONNECTIONS

2,277 EMPLOYEES WORLD-WIDE

$9.4 BILLION TOTAL ASSETS

CAD$6.7 **BILLION** MARKET CAP*

US$4.9 **BILLION** MARKET CAP*

7,504 KM OF **GAS DISTRIBUTION LINES**

11,637 KM OF **ELECTRICITY DISTRIBUTION LINES**

2,368 KM **OF WATER DISTRIBUTION MAINS**

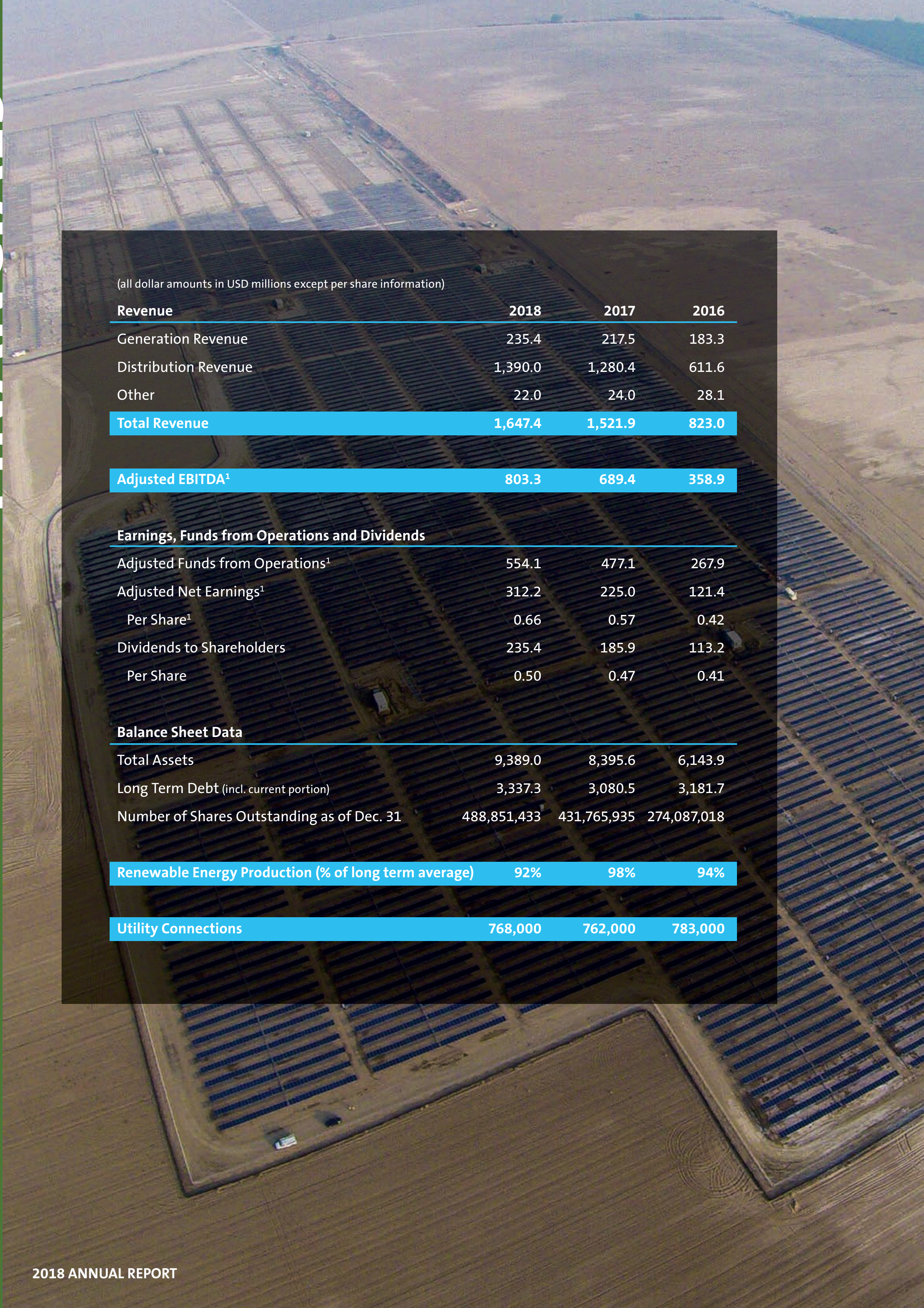
713 WIND TURBINES

773,980 SOLAR PANELS

57 HYDROELECTRIC GENERATORS

*Market cap is based on the AQN closing price on the NYSE and TSX as at December 31, 2018.

FINANCIALS



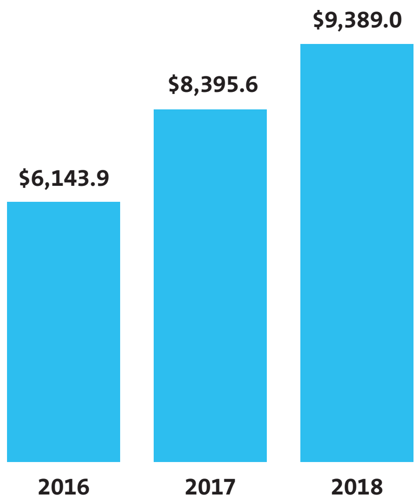
(all dollar amounts in USD millions except per share information)

Revenue	2018	2017	2016
Generation Revenue	235.4	217.5	183.3
Distribution Revenue	1,390.0	1,280.4	611.6
Other	22.0	24.0	28.1
Total Revenue	**1,647.4**	**1,521.9**	**823.0**
Adjusted EBITDA[1]	**803.3**	**689.4**	**358.9**
Earnings, Funds from Operations and Dividends			
Adjusted Funds from Operations[1]	554.1	477.1	267.9
Adjusted Net Earnings[1]	312.2	225.0	121.4
Per Share[1]	0.66	0.57	0.42
Dividends to Shareholders	235.4	185.9	113.2
Per Share	0.50	0.47	0.41
Balance Sheet Data			
Total Assets	9,389.0	8,395.6	6,143.9
Long Term Debt (incl. current portion)	3,337.3	3,080.5	3,181.7
Number of Shares Outstanding as of Dec. 31	488,851,433	431,765,935	274,087,018
Renewable Energy Production (% of long term average)	**92%**	**98%**	**94%**
Utility Connections	**768,000**	**762,000**	**783,000**

FINANCIAL HIGHLIGHTS

STRONG FINANCIAL POSITION

Total Assets
in Millions



Revenue

$1.65 BILLION

↑8%

Adjusted EBITDA[1]

$803 MILLION

↑17%

Adjusted Net Earnings Per Common Share[1]

$0.66

↑16%

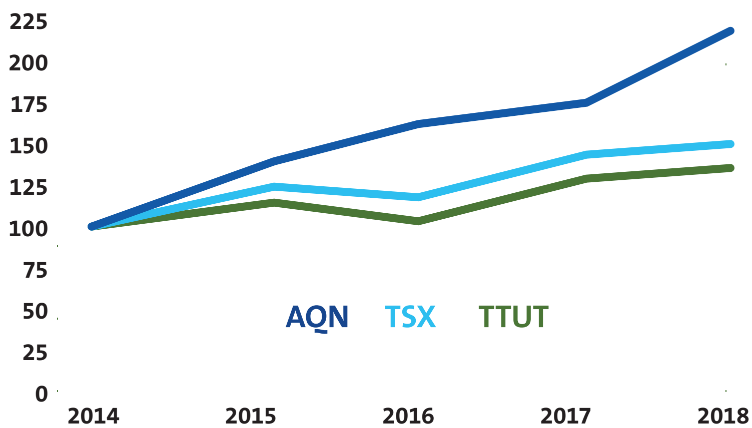
Adjusted Funds From Operations[1]

$554 MILLION

↑16%

DELIVERING VALUE TO SHAREHOLDERS

Compelling Total Shareholder Return



Further growth in the common share dividend in 2018[2]

$0.51

↑10%

1. The terms "adjusted EBITDA", "adjusted net earnings", "adjusted net earnings per share", and "adjusted funds from operations" (together, the "Financial Measures") are used throughout this Annual Report. The Financial Measures are not recognized measures under generally accepted accounting principles in the United States. There is no standardized measure of the Financial Measures, consequently Algonquin'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 further discussion, calculation and analysis of these Financial Measures can be found in the Management Discussion & Analysis section of this Annual Report.

2. Amount shown represents the annualized dividend using the quarterly dividend rate as of Q2, 2018 of US$0.1282/share.

LIBERTY UTILITIES

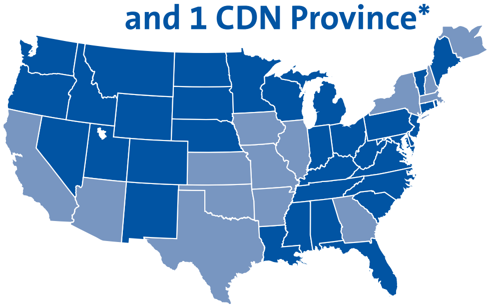
EXPANDING OUR DISTRIBUTION FOOTPRINT

Liberty Utilities owns and operates a diversified portfolio of regulated electric, natural gas, water distribution and wastewater collection utility systems and transmission operations which collectively serve the needs of approximately 768,000 connections throughout the United States.

Liberty Utilities seeks to provide safe, high quality, and reliable services to its customers, as well as deliver stable and predictable earnings to Algonquin. In addition to encouraging and supporting organic growth within its existing service territories, Liberty Utilities seeks to deliver continued growth in earnings through accretive acquisitions of additional utility systems.

In 2018, Liberty Utilities announced that it entered into an agreement to purchase New Brunswick Gas, a regulated utility that provides natural gas to approximately 12,000 customers in 12 communities across New Brunswick, and operates approximately 800 km of natural gas distribution pipeline. This acquisition is an exciting achievement for Liberty Utilities as its first regulated utility asset in Canada.

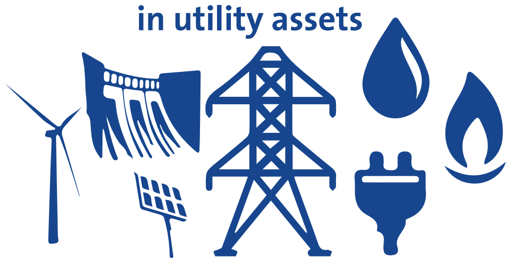
40 utilities
spanning 13 U.S. States and 1 CDN Province*



*Includes pending St. Lawrence Gas and NB Gas acquisitions

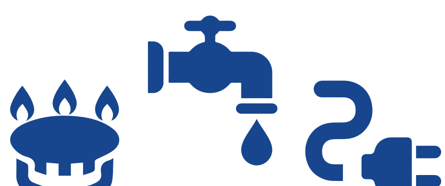
> "Our regulated utility operations provide stable, predictable earnings across our diversified customer base while also presenting unique investment opportunities to underscore our growth."

$6 billion
in utility assets



Water, natural gas, and electric distribution utilities; electric and natural gas transmission; rate-base generation assets

Over 768,000
utility connections



338,000 natural gas

164,000 water and wastewater

266,000 electric

LIBERTY POWER

> Our non-regulated generation platform boasts a significant growth pipeline, anticipating approximately 1 GW of new development opportunities in the next five years.

30%
Canada

70%
U.S.

DIVERSIFIED FLEET WITH A GLOBAL REACH

Liberty Power owns and operates a diversified portfolio of non-regulated renewable and clean power generation assets located across North America. Liberty Power's diversified fleet of hydroelectric, wind, solar and thermal facilities have a combined gross generating capacity of approximately 1.5 GW, with 86% of its electric output sold pursuant to long-term contractual arrangements which have a production-weighted average remaining contract life of 14 years.

In 2018, Liberty Power successfully added 150 MW of generation capacity to its portfolio with the commencement of commercial operations of the Great Bay Solar Facility in Maryland and the Amherst Island Wind Facility in Ontario.

14 years
Average Power Purchase Agreement (PPA) length

$3.3 Billion
in power assets

1.5 GW gross generating capacity in wind, solar, hydroelectric, and thermal power generation facilities in North America.

HIGHLIGHTS & KEY INTIATIVES

Image courtesy of photographer Roger Nomer and The Joplin Globe.

SUSTAINABILITY IS WOVEN INTO OUR BUSINESS MODEL

At Algonquin, we have always taken our role in helping to create a sustainable future seriously. We have made, and will continue to make, a positive impact on the environment and society for the benefit of future generations.

So how are we doing that?

Over the course of 2018, several initiatives were pursued in support of our sustainability efforts:

- We **commissioned two renewable energy facilities** which bring new supplies of emissions-free electricity to our communities.
- Our **environmental measurement, reporting and performance practices** were further strengthened with the continued roll-out of our enterprise-wide Environmental Management System.
- We conducted our annual **Employee Engagement Survey**, which provides invaluable perspective on the evolving needs and interests of our employees throughout North America.
- In alignment with the United Nations Sustainable Development Goals, we published our **Sustainability Policy**, which serves as a guide for the work we do with our customers and in our communities.

As part of our sustainability mindset throughout Algonquin, we strive to deliver clean, efficient, and reliable energy to facilitate the transition to low carbon energy sources and provide clean water to our communities. Our local approach fosters open and constructive collaboration with the communities in which we operate – an essential step in ensuring we are developing solutions that respect the unique needs of all stakeholders, today and in the years to come.

A SOARING EXAMPLE OF OUR LOCAL PARTNERSHIP AND INNOVATIVE THINKING

Missouri has a large population of peregrine falcons that plays an important role in the local ecosystem. These falcons hunt starlings, pigeons and other city birds that can cause health issues for residents and for employees at our power plants, while also impacting local agriculture. Working with the Missouri Department of Conservation, Algonquin set up artificial nest boxes at several generating stations to attract peregrines who act as a deterrent for the city birds. This solution is a win-win-win for the local community, Algonquin, and the local population of peregrines and can act as a model for our other facilities throughout North America.

SAFETY EXCELLENCE – ROOTED IN SUSTAINABILITY

Our commitment to the triple bottom line — social, environmental and economic sustainability — is the foundation for safe, reliable and agile operations. While sustainability is about what we do and how we get it done, safety is the study of the right way to do things. This means safety is at the core of sustainability, and operating a sustainable business comes with ensuring the safety, health, and well-being of our most vital resource – our people. Through sustained focus, participation and commitment to our Environmental Health and Safety programs, we will continue our journey to Safety Excellence. Algonquin achieved lost time and recordable injury rates well below the Bureau of Labour Statistics pro-rata average for industry peers – a standout achievement.

ADVANCING OUR STRATEGIC PLAN

Our people delivered many notable achievements across the company in 2018. We saw the completion of 150 MW of sustainable new wind and solar capacity, welcomed further regulatory progress in support of our Customer Saving Plan initiative, announced the agreement to acquire New Brunswick Gas, and made further investment in Atlantica Yield, to name a few. Here are more details on those initiatives and other key corporate highlights:

Continued progress on our Customer Savings Plan – Within Liberty Utilities, we continue to make positive progress toward our goal of developing up to 600 MW of sustainable, cost-effective wind power to serve the needs of electricity customers within our Midwest electric service territory. Our Customer Savings Plan is a shining example of our efforts to transition our power generating fleet to sustainable sources of clean energy.

Completed new solar and wind projects totaling 150 MW – Two new renewable energy facilities started commercial operations in 2018, including our 75 MW Great Bay Solar Facility located in Somerset County, Maryland (March, 2018) and our 75 MW Amherst Island Wind Facility in Ontario (June, 2018).

Further commitment to international project development through AAGES and Atlantica – Having launched the initial stages of our Abengoa-Algonquin Global Energy Solutions ("AAGES") joint venture and Atlantica investment in November of 2017, we took further steps to strengthen our commitment to international infrastructure development in 2018. In April 2018, we expanded our commitment to Atlantica with an agreement to acquire a further 16.5% common equity interest (transaction closed in November, 2018).

Our AAGES partnership and Atlantica investment represent our commitment to measured expansion of both our geographic reach and our expertise in ways that are highly complementary to our mission of delivering long-term, sustainable value to our shareholders.

Achieved successful rate review outcomes – Over the course of 2018, we successfully completed rate reviews across a number of our utilities, representing a cumulative annualized revenue increase of approximately $24.5 million.

Funding growth – We completed two common equity financings totaling approximately C$615 million to fund our strategic growth plan.

Announced New Brunswick Gas Acquisition – In December 2018, we entered into an agreement to purchase New Brunswick Gas for C$331 million. The transaction, which adds approximately 12,000 customers in 12 communities across New Brunswick and is our first Canadian utility acquisition, is expected to close in 2019.

Robust Risk Management Practices - Starting at the Board level with our Risk Committee and reaching down into all levels of our organization with risk management teams, programs, and employee training, Enterprise Risk Management is an essential component of our operations. Operational foresight, early risk detection, and rapid mitigation are goals that ensure the best possible outcomes for our business. Algonquin was honored to have been recognized for its Best Practices in Enterprise Risk Management in 2018.

> "2018 marked the beginning of many changes for our company, all of which will improve collaboration, reduce barriers to work, and continue to build a unified company culture."

LETTER FROM THE CEO & CHAIR

2018 – A YEAR OF MOMENTUM AND CELEBRATION

This year marked Algonquin's celebration of 30 years of business. From our founding focus on developing small, run-of-river renewable hydro projects in Ontario, we have expanded to a diversified power and utility services company, owning and operating an international portfolio of renewable electric generation facilities and water, natural gas and electricity networks. We are proud to have delivered this growth while providing a superior return on shareholder investment.

STRONG PERFORMANCE FROM A STABLE, GROWING BUSINESS

2018 saw a continuation of the growth trajectory, with Adjusted EBITDA and Adjusted Net Earnings per Share increasing annually by 17% and 16%, respectively. Our consistent growth and strong financial performance supported a 10% increase in our common share dividend, extending Algonquin's track record of superior dividend growth.

We are pleased to report that our share price has progressed in lock step with our financial performance. Our Total Shareholder Return ("TSR") – a key measure of our ability to build value in our business – has shown peer-leading performance with an average annualized TSR of 25.6% over the past 10 years, significantly surpassing the returns of both the S&P/TSX Composite Index and the S&P/TSX Capped Utilities Index over the same timeframe.

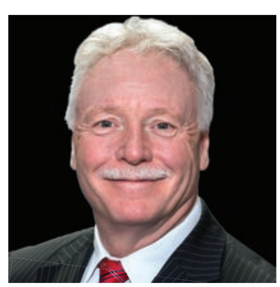
SUSTAINABILITY – OUR HISTORY AND OUR FUTURE

Sustainability has been in our corporate DNA since our founding 30 years ago. In 2018, we codified our commitment to Sustainability through our Corporate Sustainability Policy which highlights the many areas in which Algonquin has and will continue to make a meaningful contribution to a sustainable water and energy future. Our strategic plan is focused on putting these words into action.

THE PATH AHEAD – 2019 AND BEYOND

We continue to set ambitious goals for operational excellence, superior financial performance, and accretive growth. Realization of our five-year, $7.5 billion investment growth plan will be driven by our culture of entrepreneurialism and innovation.

As with many things in life, we owe our success to a combination of factors; the agile and entrepreneurial mindset demonstrated by our dedicated team of power and utility professionals, the thoughtful guidance from our Board of Directors and the continued support of our investors. We thank you all and renew our commitment to maintaining your trust and support as we continue to meaningfully contribute to a sustainable energy and water future.



Ian Robertson
CEO

Ken Moore
Chairman of the Board of Directors

ALGONQUIN
Power & Utilities Corp.

Management Discussion & Analysis

Management of Algonquin Power & Utilities Corp. (“APUC” or the “Company” or the “Corporation”) has prepared the following discussion and analysis to provide information to assist its shareholders' understanding of the financial results for the three and twelve months ended December 31, 2018. This Management Discussion & Analysis (“MD&A”) should be read in conjunction with APUC's annual audited consolidated financial statements for the years ended December 31, 2018 and 2017. This material is available on SEDAR at www.sedar.com, on EDGAR at www.sec.gov/edgar, and on the APUC website at www.AlgonquinPowerandUtilities.com. Additional information about APUC, including the most recent Annual Information Form (“AIF”) can be found on SEDAR at www.sedar.com and on EDGAR at www.sec.gov/edgar.

Unless otherwise indicated, financial information provided for the years ended December 31, 2018 and 2017 has been prepared in accordance with generally accepted accounting principles in the United States (“U.S. GAAP”). As a result, the Company's financial information may not be comparable with financial information of other Canadian companies that provide financial information on another basis.

All monetary amounts are in thousands of U.S. dollars, except where otherwise noted. We denote any amounts denominated in Canadian dollars with "C$" immediately prior to the stated amount.

This MD&A is based on information available to management as of February 28, 2019.

Caution Concerning Forward-looking Statements, Forward-looking Information and Non-GAAP Measures

Forward-looking Statements and Forward-Looking Information

This document may contain statements that constitute "forward-looking information" within the meaning of applicable securities laws in each of the provinces of Canada and the respective policies, regulations and rules under such laws or "forward-looking statements" within the meaning of the U.S. Private Securities Litigation Reform Act of 1995 (collectively, “forward-looking information”). The words “anticipates”, “believes”, “budget”, “could”, “estimates”, “expects”, “forecasts”, “intends”, “may”, “might”, “plans”, “projects”, “schedule”, “should”, “will”, “would” and similar expressions are often intended to identify forward-looking information, although not all forward-looking information contains these identifying words. Specific forward-looking information in this document includes, but are not limited to, statements relating to: expected future growth and results of operations; liquidity, capital resources and operational requirements; rate reviews, including resulting decisions and rates and expected impacts and timing; sources of funding, including adequacy and availability of credit facilities, debt maturation and future borrowings; expectations regarding the use of proceeds from equity financing; ongoing and planned acquisitions, projects and initiatives, including expectations regarding costs, financing, results and completion dates; expectations regarding the Company's corporate development activities and the results thereof; expectations regarding the cost of operations, capital spending and maintenance, and the variability of those costs; expected future capital investments, including expected timing, investment plans, sources of funds and impacts; expectations regarding generation availability, capacity and production; expectations regarding the outcome of existing or potential legal and contractual claims and disputes; expectations regarding the ability to access the capital market on reasonable terms; strategy and goals; 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; failure to identify, acquire or develop 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 or joint ventures; Atlantica or the Corporation's joint venture with Abengoa acting in a manner contrary to the Corporation's interests; a drop in the market value of Atlantica's ordinary shares; facilities being condemned or otherwise taken by governmental entities; increased external-stakeholder activism adverse to the Corporation's interests; and fluctuations in the price and liquidity of the Corporation's Common Shares. Although the Corporation has attempted to identify important factors that could cause actual actions, events or results to differ materially from those described in forward-looking information, there may be other factors that cause actions, events or results not to be as anticipated, estimated or intended. Some of these and other factors are discussed in more detail under the heading "*Enterprise Risk Management*" and in the Corporation's most recent AIF.

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

Non-GAAP Financial Measures

The terms "Adjusted Net Earnings", "Adjusted Earnings Before Interest, Taxes, Depreciation and Amortization" ("Adjusted EBITDA"), "Adjusted Funds from Operations", "Net Energy Sales", "Net Utility Sales" and "Divisional Operating Profit" are used throughout this MD&A. The terms "Adjusted Net Earnings", "Adjusted Funds from Operations", "Adjusted EBITDA", "Net Energy Sales", "Net Utility Sales" and "Divisional Operating Profit" are not recognized measures under U.S. GAAP. There is no standardized measure of "Adjusted Net Earnings", "Adjusted EBITDA", "Adjusted Funds from Operations", "Net Energy Sales", "Net Utility Sales", and "Divisional Operating Profit"; consequently, APUC's method of calculating these measures may differ from methods used by other companies and therefore may not be comparable to similar measures presented by other companies. A calculation and analysis of "Adjusted Net Earnings", "Adjusted EBITDA", "Adjusted Funds from Operations", "Net Energy Sales", "Net Utility Sales", and "Divisional Operating Profit" can be found throughout this MD&A.

Adjusted EBITDA

Adjusted EBITDA is a non-GAAP measure used by many investors to compare companies on the basis of ability to generate cash from operations. APUC uses these calculations to monitor the amount of cash generated by APUC as compared to the amount of dividends paid by APUC. APUC uses Adjusted EBITDA to assess the operating performance of APUC without the effects of (as applicable): depreciation and amortization expense, income tax expense or recoveries, acquisition costs, litigation expenses, interest expense, gain or loss on derivative financial instruments, write down of intangibles and property, plant and equipment, earnings attributable to non-controlling interests, non-service pension and post-employment costs, cost related to tax equity financing, gain or loss on foreign exchange, earnings or loss from discontinued operations, changes in value of investments carried at fair value, and other typically non-recurring items. APUC adjusts for these factors as they may be non-cash, unusual in nature and are not factors used by management for evaluating the operating performance of the Company. APUC believes that presentation of this measure will enhance an investor's understanding of APUC's operating performance. Adjusted EBITDA is not intended to be representative of cash provided by operating activities or results of operations determined in accordance with U.S. GAAP, and can be impacted positively or negatively by these items.

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, changes in value of investments carried at fair value, and other typically non-recurring items as these are not reflective of the performance of the underlying business of APUC. The Non-cash accounting charge related to the revaluation of U.S. deferred income tax assets and liabilities as a result of implementation of the effects of U.S. Tax Reform is adjusted as it is also considered a non-recurring item not reflective of the performance of the underlying business of APUC. APUC believes that analysis and presentation of net earnings or loss on this basis will enhance an investor's understanding of the operating performance of its businesses. Adjusted Net Earnings is not intended to be representative of net earnings or loss determined in accordance with U.S. GAAP, and can be impacted positively or negatively by these items.

Adjusted Funds from Operations

Adjusted Funds from Operations is a non-GAAP measure used by investors to compare cash flows from operating activities without the effects of certain volatile items that generally have no current economic impact or items such as acquisition expenses that are viewed as not directly related to a company's operating performance. APUC uses Adjusted Funds from Operations to assess its performance without the effects of (as applicable): changes in working capital balances, acquisition expenses, litigation expenses, cash provided by or used in discontinued operations and other typically non-recurring items affecting cash from operations as these are not reflective of the long-term performance of the underlying businesses of APUC. APUC believes that analysis and presentation of funds from operations on this basis will enhance an investor's understanding of the operating performance of its businesses. Adjusted Funds from Operations is not intended to be representative of cash flows from operating activities as determined in accordance with GAAP, and can be impacted positively or negatively by these items.

Net Energy Sales

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

Net Utility Sales

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

Divisional Operating Profit

Divisional Operating Profit is a non-GAAP measure. APUC uses Divisional Operating Profit to assess the operating performance of its business groups without the effects of (as applicable): depreciation and amortization expense, corporate administrative expenses, income tax expense or recoveries, acquisition costs, litigation expenses, interest expense, gain or loss on derivative financial instruments, write down of intangibles and property, plant and equipment, gain or loss on foreign exchange, earnings or loss from discontinued operations, non-service pension and post-employment costs, and other typically non-recurring items. APUC adjusts for these factors as they may be non-cash, unusual in nature and are not factors used by management for evaluating the operating performance of the divisional units. Divisional Operating Profit is calculated inclusive of interest, dividend and equity income earned from indirect investments, and Hypothetical Liquidation at Book Value ("HLBV") income, which represents the value of net tax attributes earned in the period from electricity generated by certain of its U.S. wind power and U.S. solar generation facilities. APUC believes that presentation of this measure will enhance an investor's understanding of APUC's divisional operating performance. Divisional Operating Profit is not intended to be representative of cash provided by operating activities or results of operations determined in accordance with U.S. GAAP.

Capitalized terms used herein and not otherwise defined will have the meanings assigned to them in the Company's most recent AIF.

Overview and Business Strategy

APUC is incorporated under the *Canada Business Corporations Act*. APUC owns and operates a diversified portfolio of regulated and non-regulated generation, distribution, and transmission utility assets which are expected to deliver predictable earnings and cash flows. APUC seeks to maximize total shareholder value through real per share growth in earnings and cash flows to support a growing dividend and share price appreciation.

APUC's current quarterly dividend to shareholders is $0.1282 per common share or $0.5128 per common share per annum. Based on exchange rates as at February 27, 2019, the quarterly dividend is equivalent to C$0.1685 per common share or C$0.6740 per common share per annum. APUC believes its annual dividend payout allows for both an immediate return on investment for shareholders and retention of sufficient cash within APUC to fund growth opportunities. Changes in the level of dividends paid by APUC are at the discretion of the APUC Board of Directors (the "Board"), with dividend levels being reviewed periodically by the Board in the context of APUC's financial performance and growth prospects.

APUC's operations are organized across two primary North American business units consisting of: the Liberty Utilities Group, which primarily owns and operates a portfolio of regulated electric, natural gas, water distribution and wastewater collection utility systems, and transmission operations; and the Liberty Power Group, which owns and operates a diversified portfolio of non-regulated renewable and thermal electric generation assets. APUC also owns a 41.5% beneficial stake in Atlantica Yield plc (NASDAQ: AY) ("Atlantica"), a company that acquires, owns and manages a diversified international portfolio of contracted renewable energy, power generation, electric transmission, and water assets. The investment in Atlantica is reported under the Liberty Power Group.

Liberty Utilities Group

The Liberty Utilities Group operates a diversified portfolio of regulated utility systems throughout the United States serving approximately 768,000 connections. The Liberty Utilities Group seeks to provide safe, high quality, and reliable services to its customers and to deliver stable and predictable earnings to APUC. In addition to encouraging and supporting organic growth within its service territories, the Liberty Utilities Group seeks to deliver continued growth in earnings through accretive acquisitions 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 which together serve approximately 266,000 electric connections. The group also owns and manages generating assets with a gross capacity of approximately 1.7 GW and has investments in a further approximately 0.3 GW of net generation capacity.

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 which together serve approximately 338,000 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 164,000 connections.

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 and operates hydroelectric, wind, solar, and thermal facilities with a combined gross generating capacity of approximately 1.5 GW. Approximately 86% of the electrical output is sold pursuant to long term contractual arrangements which as of December 31, 2018 had a production-weighted average remaining contract life of approximately 14 years.

APUC has a 41.5% interest in Atlantica. Atlantica owns and operates a portfolio of international clean energy and water infrastructure assets under long term contracts with a Cash Available for Distribution ("CAFD") weighted average remaining contract life of approximately 18 years.

Corporate Development

The Company's development activities for projects either owned directly by the Company or indirectly through AAGES entities are undertaken primarily by Abengoa-Algonquin Global Energy Solutions ("AAGES"), a joint venture with Abengoa S.A (MC: ABG) ("Abengoa"), an international infrastructure construction company. AAGES and its affiliates work with a global reach to identify, develop, and construct new renewable power generating facilities, power transmission lines, and water infrastructure assets. Once a project developed by AAGES has reached commercial operations ("COD"), APUC will work with AAGES to jointly determine whether it will be optimal for such project to be held by APUC, remain in AAGES, or be offered for sale to Atlantica or, in limited circumstances, another party.

2018 Major Highlights

Corporate Highlights

Operating Results

APUC operating results relative to the same period last year are as follows:

	Three Months Ended December 31			Twelve Months Ended December 31		
(all dollar amounts in $ millions except per share information)	2018	2017	Change	2018	2017	Change
Net earnings attributable to shareholders	**$44.0**	$47.2	**(7)%**	**$185.0**	$149.5	**24%**
Adjusted Net Earnings[1]	**$70.5**	$67.0	**5%**	**$312.2**	$225.0	**39%**
Adjusted EBITDA[1]	**$196.9**	$185.8	**6%**	**$803.3**	$689.4	**17%**
Net earnings per common share	**$0.09**	$0.11	**(18)%**	**$0.38**	$0.37	**3%**
Adjusted Net Earnings per common share[1]	**$0.14**	$0.16	**(13)%**	**$0.66**	$0.57	**16%**

1 See *Non-GAAP Financial Measures*.

Declaration of 2019 First Quarter Dividend of $0.1282 (C$0.1685) per Common Share

APUC currently targets an industry leading annual growth in dividends payable to shareholders underpinned by increases in earnings and cashflow. In setting the appropriate dividend level, the Board of APUC considers the Company’s current and expected growth in earnings per share as well as dividend payout ratio as a percentage of earnings per share and cash flow per share.

On February 28, 2019, APUC announced that the Board of APUC declared a first quarter 2019 dividend of $0.1282 per common share payable on April 15, 2019 to shareholders of record on March 29, 2019. Based on the Bank of Canada exchange rate on February 27, 2019, the Canadian dollar equivalent for the first quarter 2019 dividend is set at C$0.1685 per common share.

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

	Q2 2018	Q3 2018	Q4 2018	Q1 2019	Total
U.S. dollar dividend	$0.1282	$0.1282	$0.1282	$0.1282	$0.5128
Canadian dollar equivalent	$0.1648	$0.1673	$0.1679	$0.1685	$0.6685

Completed formation of AAGES Joint Venture with Abengoa

On March 9, 2018, APUC entered into an agreement to create AAGES, a joint venture with Abengoa S.A. ("Abengoa"), to identify, develop, and construct clean energy and water infrastructure assets.

Investment in Atlantica

In 2018, APUC purchased a 41.5% equity interest in Atlantica. Atlantica owns and manages a diversified international portfolio of contracted renewable energy, power generation, electric transmission, and water assets. The purchase was completed in two tranches.

On March 9, 2018, APUC acquired a 25% equity interest in Atlantica for a total purchase price of approximately $608 million, based on a price of $24.25 per ordinary share of Atlantica. On November 27, 2018, APUC purchased an additional 16.5% equity interest in Atlantica for a purchase price of approximately $345 million, based on a price of $20.90 per ordinary share of Atlantica.

The investment is expected to be immediately accretive to APUC's earnings and cash flows. The Company has included within its 2018 operating results $39.3 million of dividends received from Atlantica.

Fitch Initiates First-Time Ratings to Algonquin Power & Utilities Corp. and Subsidiaries

On July 20, 2018, Fitch Ratings, Inc. ("Fitch") assigned a BBB Long-Term Issuer Default Rating ("IDR") and an F2 Short-Term IDR to APUC and Liberty Utilities Co. ("LUCo"), the parent company for the Liberty Utilities Group. Fitch assigned a BBB Long-Term IDR and an F3 Short-Term IDR to Algonquin Power Co ("APCo"), the parent company for the Liberty Power Group. The rating outlook for each entity is stable. Fitch also assigned a BBB+ rating to the senior unsecured debt issued by Liberty Utilities Finance GP1 ("Liberty Finance"), a special purpose financing entity of LUCo. See *Treasury Risk Management-Downgrade in the Company's Credit Rating Risk*.

DBRS Upgrades APUC and APCo Issuer Ratings to BBB with a Stable Trend

Subsequent to year end, DBRS Limited ("DBRS") upgraded the issuer rating of APUC and APCo to BBB with a stable trend and APUC's preferred share rating to Pfd-3. The APCo upgrade reflects the agency's view of increased scale and a solid business risk profile resulting from long term contracted power assets. The APUC rating upgrade reflects the agency's view of a significant improvement in the Company's business risk profile following the acquisition and successful integration of The Empire District Electric Company ("Empire") as well as strong cash flows underpinned by regulated operations and contracted power assets.

Corporate Financings Completed

C$444.4 Million Common Equity Financing

On April 24, 2018, APUC closed the sale of approximately 37.5 million of its common shares to certain institutional investors at a price of C$11.85 per share, for gross proceeds of approximately C$444.4 million. The proceeds of the offering were used to pay down existing indebtedness and to fund in part the purchase of the additional 16.5% interest in Atlantica.

Issuance of Fixed-to-Floating Subordinated Notes

On October 17, 2018, APUC issued $287.5 million of 60 (non-call 5) year fixed-to-floating 6.875% subordinated notes. The offering represents APUC's inaugural entry into the U.S. public debt markets (see *Long Term Debt*).

C$172.5 Million Common Equity Financing

On December 20, 2018, APUC closed the sale of approximately 12.5 million of its common shares to certain institutional investors at a price of C$13.76 per share, for gross proceeds of approximately C$172.5 million. The proceeds of the offering will be used to partially finance the acquisition of Enbridge Gas New Brunswick Limited Partnership ("New Brunswick Gas") (*see Major Highlights - Liberty Utilities)*, and for general corporate purposes.

Change to U.S. Dollar Reporting

Effective the first quarter of 2018, APUC's interim and annual consolidated financial statements are now 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 provides 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 Utilities Group Highlights

Successful Rate Review 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 2018 and 2019 year to date, the Liberty Utilities Group successfully completed several rate reviews representing a cumulative annualized revenue increase of approximately $24.5 million. In addition progress was made in advancing several regulatory mechanisms. In New Hampshire and Missouri the Public Utilities Commissions approved revenue decoupling as part of their orders.

Resolution with Regulators Regarding the Impacts of Tax Reform

On December 22, 2017, the Tax Cuts and Jobs Act ("U.S. Tax Reform") was signed into law which resulted in significant changes to U.S. tax law. Amongst other things, U.S. Tax Reform reduced the federal corporate income tax rates from 35% to 21%. The change in corporate tax rates has impacted regulatory revenue requirements of most public utilities, including the Liberty Utilities Group. Throughout the course of 2018, the Liberty Utilities Group obtained orders from the majority of its principal regulators covering approximately 93% of customers, resulting in the reduction of customer rates in connection with the reduction in tax rates. Collectively, the orders represent an annualized aggregate reduction in utility revenues of approximately $35 million, of which approximately $18 million has been realized in 2018.

Progress Made on Customer Savings Plan

In 2017, Empire proposed to its regulators in Missouri, Kansas, Oklahoma, and Arkansas a Customer Savings Plan which would phase out its Asbury Coal Generation Facility and develop additional wind generation in or near its service territory that will utilize all available Production Tax Credits. The plan calls for the development of up to 600 MW of sustainable, cost-effective wind power to serve the needs of electricity customers within the Liberty Utilities Group’s Midwest electric service territory and forecasts cost savings for customers of approximately $169 million and $325 million over a 20-year and 30-year period, respectively.

On July 11, 2018, Empire received an order from the Missouri Public Service Commission (“MPSC”) supporting various requests related to its proposed plan, which has allowed the Liberty Utilities Group to continue to pursue the development of up to 600 MW of wind power and recognizes that "millions of dollars of customer savings could be of considerable benefit to Empire's customers and the entire state".

On October 18, 2018, and November 18, 2018, Empire filed with the MPSC a request for Certificates of Convenience and Necessity ("CCN"), in each case for 300 MW of the 600 MW contemplated as part of the initiative. A final hearing on the merits is scheduled for April 2019.

Acquisition of New Brunswick Gas

On December 4, 2018, the Liberty Utilities Group announced that it entered into an agreement to purchase New Brunswick Gas. New Brunswick Gas is a regulated utility that provides natural gas to approximately 12,000 customers in 12 communities across New Brunswick, and operates approximately 800 km of natural gas distribution pipeline. The total purchase price for the transaction is C$331 million, subject to customary adjustments. The transaction closing is expected in 2019, following regulatory approvals.

Acquisition of Ownership Interest in Wataynikaneyap Power Transmission Project

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

Liberty Power Group Highlights

Completion of the Great Bay Solar Project

On March 29, 2018, the Great Bay Solar Facility achieved COD. The facility consists of a 75 MW solar powered electric generating facility comprised of four sites located in Somerset County in southern Maryland. The Great Bay Solar Facility is the Liberty Power Group's fourth solar generating facility and consists of 300,000 solar panels and 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 Power Purchase Agreement ("PPA"), with a 10 year extension option.

Completion of the Amherst Island Wind Project

On June 15, 2018, the Amherst Island Wind Facility achieved COD. The facility consists of a 75 MW wind powered electric generating facility located on Amherst Island near the village of Stella, approximately 15 kilometers southwest of Kingston, Ontario. The Amherst Island Wind Facility is the Liberty Power Group's 12th wind powered electric generating facility and is comprised of 26 Siemens 3.2 MW turbines and is expected to generate approximately 235.0 GW-hrs of electrical energy annually, with all energy being sold to the Independent Electricity System Operator ("IESO"), formerly the Ontario Power Authority.

Issuance of Green Bonds

Subsequent to year-end on January 29, 2019, the Liberty Power Group issued C$300.0 million of senior unsecured debentures bearing interest at 4.60% and with a maturity date of January 29, 2029. The debentures represent Liberty Power Group's inaugural "green bond" offering (see *Long Term Debt*).

2018 Fourth Quarter Results From Operations

Key Financial Information (all dollar amounts in $ millions except per share information)	Three Months Ended December 31	
	2018	**2017**
Revenue	**$ 419.9**	$ 409.5
Net earnings attributable to shareholders	**44.0**	47.2
Cash provided by operating activities	**168.6**	116.0
Adjusted Net Earnings[1]	**70.5**	67.0
Adjusted EBITDA[1]	**196.9**	185.8
Adjusted Funds from Operations[1]	**132.5**	126.0
Dividends declared to common shareholders	**63.1**	50.5
Weighted average number of common shares outstanding	**477,450,181**	412,632,308
Per share		
Basic net earnings	**$ 0.09**	$ 0.11
Diluted net earnings	**$ 0.09**	$ 0.11
Adjusted Net Earnings[1,2]	**$ 0.14**	$ 0.16
Dividends declared to common shareholders	**$ 0.13**	$ 0.12

[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, 2018, APUC experienced an average exchange rate of Canadian to U.S. dollar of approximately 0.7568 as compared to 0.7865 in the same period in 2017. As such, any quarter over quarter variance in revenue or expenses, in local currency, at any of APUC's Canadian entities is affected by a change in the average exchange rate upon conversion to APUC's reporting currency.

For the three months ended December 31, 2018, APUC reported total revenue of $419.9 million as compared to $409.5 million during the same period in 2017, an increase of $10.4 million. The major factors resulting in the increase in APUC revenue in the three months ended December 31, 2018 as compared to the corresponding period in 2017 are set out as follows:

(all dollar amounts in $ millions)		Three Months Ended December 31
Comparative Prior Period Revenue	**$**	**409.5**
LIBERTY UTILITIES GROUP		
Existing Facilities		
Electricity: Increase is primarily due to higher heating degree days, which resulted in higher consumption at the Empire Electric System.		10.7
Gas: Increase is primarily due to higher consumption and pass through commodity costs at the Midstates, New England, Empire and EnergyNorth Gas Systems due to higher heating degree days.		6.6
Water: Decrease is primarily due to lower consumption at the Arkansas Water System and lower phased-in revenue at the White Hall Water system.		(0.4)
Other		(0.2)
		16.7
Rate Reviews		
Electricity: Implementation of lower rates at the Granite State and Empire Electric systems due to U.S. Tax reform, partially offset by rate increases at the Calpeco Electric System.		(4.4)
Gas: Implementation of new rates, partially offset by U.S. Tax Reform impact, primarily at Midstates and EnergyNorth Gas Systems.		1.7
Water: Implementation of lower rates at the Arizona and Park Water Systems due to U.S. Tax Reform.		(0.7)
		(3.4)
LIBERTY POWER GROUP		
Existing Facilities		
Hydro: Increase is primarily due to higher production and favourable rates in the Western Region partially offset by unfavourable rates in the Maritime Region.		0.9
Wind Canada: Decrease is primarily due to lower production.		(2.6)
Wind U.S.: Decrease is primarily due to lower production.		(3.4)
Solar Canada: Decrease is primarily due to lower production.		(0.1)
Solar U.S.: Decrease is primarily due to lower production.		(0.2)
Thermal: Increase is primarily due to higher production and an increase in capacity revenue at the Windsor Locks Thermal Facility earned through the second phase of a contract that began in 2018.		1.2
Other		0.4
		(3.8)
New Facilities		
Solar US: Great Bay Solar Facility achieved full COD in March 2018.		1.7
		1.7
Foreign Exchange		**(0.8)**
Current Period Revenue	**$**	**419.9**

A more detailed discussion of these factors is presented within the business unit analysis.

For the three months ended December 31, 2018, net earnings attributable to shareholders totaled $44.0 million as compared to $47.2 million during the same period in 2017, a decrease of $3.2 million or 6.8%. The decrease was due to a $10.2 million decrease in earnings from operating facilities, $46.0 million loss due to change in fair value of an investment carried at fair value, $6.9 million increase in interest expense, $0.3 million increase in administration charges and a $2.8 million decrease in gains from derivative instruments. These items were partially offset by a $9.9 million decrease in acquisition related costs, $5.4 million decrease in depreciation and amortization expenses, $0.6 million increase in foreign exchange gain, a $1.1 million decrease in pension and post-employment non-service costs, $17.5 million increase in interest, dividend, equity and other income primarily from the investment in Atlantica, $1.4 million increase in other gains, $0.2 million increase in net effect of non-controlling interests, and a $26.9 million decrease in income tax expense (tax explanations are discussed in *APUC: Corporate and Other Expenses)* as compared to the same period in 2017.

During the three months ended December 31, 2018, cash provided by operating activities totaled $168.6 million as compared to $116.0 million during the same period in 2017. During the three months ended December 31, 2018, Adjusted Funds from Operations totaled $132.5 million as compared to $126.0 million during the same period in 2017.

During the three months ended December 31, 2018, Adjusted EBITDA totaled $196.9 million as compared to $185.8 million during the same period in 2017, an increase of $11.1 million or 6.0%. 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*).

2018 Annual Results From Operations

Key Financial Information	**Twelve Months Ended December 31**		
(all dollar amounts in $ millions except per share information)	**2018**	**2017**	**2016**
Revenue	**$ 1,647.4**	$ 1,521.9	$ 823.0
Net earnings attributable to shareholders	**185.0**	149.5	97.9
Cash provided by operating activities	**530.4**	326.6	229.5
Adjusted Net Earnings[1]	**312.2**	225.0	121.4
Adjusted EBITDA[1]	**803.3**	689.4	358.9
Adjusted Funds from Operations[1]	**554.1**	477.1	267.9
Dividends declared to common shareholders	**235.4**	185.9	113.2
Weighted average number of common shares outstanding	**461,818,023**	382,323,434	271,832,430
Per share			
Basic net earnings	**$ 0.38**	$ 0.37	$ 0.33
Diluted net earnings	**$ 0.38**	$ 0.37	$ 0.33
Adjusted Net Earnings[1,2]	**$ 0.66**	$ 0.57	$ 0.42
Dividends declared to common shareholders	**$ 0.50**	$ 0.47	$ 0.41
Total assets	**9,389.0**	8,395.6	6,143.9
Long term debt[3]	**3,337.3**	3,080.5	3,181.7

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, 2018, APUC experienced an average exchange rate of Canadian to U.S. of approximately 0.7715 as compared to 0.7705 in the same period in 2017. As such, any year-over-year variance in revenue or expenses, in local currency, at any of APUC's Canadian entities is affected by a change in the average exchange rate upon conversion to APUC's reporting currency.

For the twelve months ended December 31, 2018, APUC reported total revenue of $1,647.4 million as compared to $1,521.9 million during the same period in 2017, an increase of $125.5 million or 8.2%. The major factors resulting in the increase in APUC revenue for the twelve months ended December 31, 2018 as compared to the corresponding period in 2017 are set out as follows:

(all dollar amounts in $ millions)		Twelve Months Ended December 31
Comparative Prior Period Revenue	**$**	**1,521.9**
LIBERTY UTILITIES GROUP		
Existing Facilities		
Electricity: Increase is primarily due to higher heating degree days in the first & fourth quarters, and higher cooling degree days in the second & third quarters of the year, which resulted in higher consumption and pass through commodity costs at the Empire Electric System.		71.4
Gas: Increase is primarily due to favourable weather resulting in higher consumption and higher pass through commodity costs at the Midstates, EnergyNorth, New England and Empire Gas Systems.		48.1
Water: Decrease is primarily due to divestiture of the Mountain Water System from condemnation proceedings on June 22, 2017.		(10.4)
Other		(0.3)
		108.8
Rate Reviews		
Electricity: Implementation of lower rates at the Empire Electric System due to U.S. Tax Reform, partially offset by rate increases at the Calpeco Electric System.		(3.7)
Gas: Implementation of new rates, net of U.S. Tax Reform impact, primarily at the Midstates and EnergyNorth Gas Systems.		5.4
Water: Implementation of lower rates at the Arizona and Park Water Systems due to U.S. Tax Reform.		(1.3)
		0.4
LIBERTY POWER GROUP		
Existing Facilities		
Hydro: Decrease is primarily due to lower production and the recognition of a bonus payment from Hydro Quebec in the prior year, partially offset by favourable rates in the Western Region.		(2.5)
Wind Canada: Decrease is primarily due to lower overall production.		(2.5)
Wind U.S.: Decrease is primarily due to lower production and unfavourable market rates at the Senate Wind Facility, partially offset by favourable market rates at the Shady Oaks, Sandy Ridge and Minonk Wind Facilities.		(5.5)
Solar Canada: Increase is primarily due to higher production.		0.1
Thermal: Increase is primarily due to higher overall production as well as an increase in capacity revenue at the Windsor Locks Thermal Facility earned through the second phase of a contract that began in 2018.		12.1
Other: Increase is primarily due to higher management fee from managed companies.		0.8
		2.5
New Facilities		
Wind U.S.: Acquisition of Deerfield Wind Facility in March 2017.		6.0
Solar U.S.: Great Bay Solar Facility reached full COD in March 2018.		7.6
		13.6
Foreign Exchange		**0.2**
Current Period Revenue	**$**	**1,647.4**

A more detailed discussion of these factors is presented within the business unit analysis.

For the twelve months ended December 31, 2018, net earnings attributable to shareholders totaled $185.0 million as compared to $149.5 million during the same period in 2017, an increase of $35.5 million. The increase was due to a $12.4 million increase in earnings from operating facilities, $43.9 million increase in interest, dividend, equity and other income received primarily from the investment in Atlantica, $47.0 million decrease in acquisition costs, $58.1 million increase in net effect of non-controlling interests, $0.4 million increase in foreign exchange gain, $3.7 million decrease in interest expense, a $5.1 million decrease in pension and post-employment non-service costs, and a $20.0 million decrease in income tax expense (tax explanations are discussed in *APUC: Corporate and Other Expenses*). These items were partially offset by a $138.0 million loss due to change in fair value of an investment carried at fair value, $3.1 million increase in administration charges, $9.5

million increase in depreciation and amortization expenses, $2.0 million increase in other losses, and a $2.5 million decrease on gains from derivative instruments.

During the twelve months ended December 31, 2018, cash provided by operating activities totaled $530.4 million as compared to $326.6 million during the same period in 2017. During the twelve months ended December 31, 2018, Adjusted Funds from Operations, a non-GAAP measure, totaled $554.1 million as compared to $477.1 million the same period in 2017, an increase of $77.0 million.

Adjusted EBITDA in the twelve months ended December 31, 2018 totaled $803.3 million as compared to $689.4 million during the same period in 2017, an increase of $113.9 million or 16.5%. 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*).

2018 Adjusted EBITDA Summary

Adjusted EBITDA (see *Non-GAAP Financial Measures*) for the three months ended December 31, 2018 totaled $196.9 million as compared to $185.8 million during the same period in 2017, an increase of $11.1 million or 6.0%. Adjusted EBITDA for the twelve months ended December 31, 2018 totaled $803.3 million as compared to $689.4 million during the same period in 2017, an increase of $113.9 million or 16.5%. The breakdown of Adjusted EBITDA by the Company's main operating segments and a summary of changes are shown below.

Adjusted EBITDA by business units	**Three Months Ended December 31**		**Twelve Months Ended December 31**	
(all dollar amounts in $ millions)	**2018**	**2017**	**2018**	**2017**
Liberty Utilities Group Operating Profit	**$ 132.9**	$ 144.4	**$ 550.5**	$ 544.2
Liberty Power Group Operating Profit	**78.7**	55.7	**303.6**	192.8
Administrative Expenses	**(15.0)**	(14.7)	**(52.7)**	(49.6)
Other Income & Expenses	**0.3**	0.4	**1.9**	2.0
Total Algonquin Power & Utilities Adjusted EBITDA	**$ 196.9**	$ 185.8	**$ 803.3**	$ 689.4
Change in Adjusted EBITDA ($)	**$ 11.1**		**$ 113.9**	
Change in Adjusted EBITDA (%)	**6.0%**		**16.5%**	

Change in Adjusted EBITDA	**Three Months Ended December 31, 2018**			
(all dollar amounts in $ millions)	**Utilities**	**Power**	**Corporate**	**Total**
Prior period balances	**$ 144.4**	**$ 55.7**	**$ (14.3)**	**$ 185.8**
Existing Facilities	(8.1)	0.6	(0.1)	(7.6)
New Facilities	—	23.0	—	23.0
Rate Reviews	(3.4)	—	—	(3.4)
Foreign Exchange Impact	—	(0.6)	—	(0.6)
Administrative Expenses	—	—	(0.3)	(0.3)
Total change during the period	**$ (11.5)**	**$ 23.0**	**$ (0.4)**	**$ 11.1**
Current period balances	**$ 132.9**	**$ 78.7**	**$ (14.7)**	**$ 196.9**

Change in Adjusted EBITDA	**Twelve Months Ended December 31, 2018**			
(all dollar amounts in $ millions)	**Utilities**	**Power**	**Corporate**	**Total**
Prior period balances	**$ 544.2**	**$ 192.8**	**$ (47.6)**	**$ 689.4**
Existing Facilities	5.9	45.0	(0.1)	50.8
New Facilities	—	65.9	—	65.9
Rate Reviews	0.4	—	—	0.4
Foreign Exchange Impact	—	(0.1)	—	(0.1)
Administration Expenses	—	—	(3.1)	(3.1)
Total change during the period	**$ 6.3**	**$ 110.8**	**$ (3.2)**	**$ 113.9**
Current period balances	**$ 550.5**	**$ 303.6**	**$ (50.8)**	**$ 803.3**

LIBERTY UTILITIES GROUP

The Liberty Utilities Group operates rate-regulated utilities that provide distribution services to approximately 768,000 connections in the natural gas, electric, water and wastewater sectors which is an increase of 6,000 connections as compared to the prior year resulting primarily from organic growth in the Liberty Utilities Group's service territories. 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			
	2018		2017	
(all dollar amounts in $ millions)	Assets	Total Connections[1]	Assets	Total Connections[1]
Electricity	$ **2,578.7**	**266,000**	$ 2,479.9	265,000
Natural Gas	**1,057.3**	**338,000**	996.1	337,000
Water and Wastewater	**481.4**	**164,000**	462.6	160,000
Total	$ **4,117.4**	**768,000**	$ 3,938.6	762,000
Accumulated Deferred Income Taxes Liability	$ **438.4**		$ 392.8	

[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 266,000 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 338,000 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 164,000 connections located in the states of Arkansas, Arizona, California, Illinois, Missouri and Texas.

2018 Annual Usage Results

Electric Distribution Systems

	Three Months Ended December 31		Twelve Months Ended December 31	
	2018	2017	2018	2017
Average Active Electric Connections For The Period				
Residential	**225,900**	224,400	**225,200**	223,700
Commercial and industrial	**37,900**	39,200	**37,800**	39,200
Total Average Active Electric Connections For The Period	**263,800**	263,600	**263,000**	262,900
Customer Usage (GW-hrs)				
Residential	**611.2**	571.7	**2,535.1**	2,320.1
Commercial and industrial	**971.2**	882.3	**3,988.9**	3,523.1
Total Customer Usage (GW-hrs)	**1,582.4**	1,454.0	**6,524.0**	5,843.2

For the three months ended December 31, 2018, the electric distribution systems' usage totaled 1,582.4 GW-hrs as compared to 1,454.0 GW-hrs for the same period in 2017, an increase of 128.4 GW-hrs or 8.8%, primarily due to higher heating degree days at the Empire Electric System.

For the twelve months ended December 31, 2018, the electric distribution systems' usage totaled 6,524.0 GW-hrs as compared to 5,843.2 GW-hrs for the same period in 2017, an increase of 680.8 GW-hrs or 11.7%. The increase is primarily due to higher heating degree days in the first and fourth quarters and higher cooling degree days in the second and third quarters at the Empire Electric System.

Natural Gas Distribution Systems

	Three Months Ended December 31		Twelve Months Ended December 31	
	2018	**2017**	**2018**	**2017**
Average Active Natural Gas Connections For The Period				
Residential	**288,900**	286,700	**288,700**	287,100
Commercial and industrial	**31,700**	31,700	**31,700**	31,700
Total Average Active Natural Gas Connections For The Period	**320,600**	318,400	**320,400**	318,800
Customer Usage (MMBTU)				
Residential	**6,186,000**	5,196,000	**20,065,000**	17,621,000
Commercial and industrial	**4,533,000**	4,282,000	**14,529,000**	12,672,000
Total Customer Usage (MMBTU)	**10,719,000**	9,478,000	**34,594,000**	30,293,000

For the three months ended December 31, 2018, usage at the natural gas distribution systems totaled 10,719,000 MMBTU as compared to 9,478,000 MMBTU during the same period in 2017, an increase of 1,241,000 MMBTU, or 13.1%. The increase is primarily due to higher heating degree days across all of the gas systems.

For the twelve months ended December 31, 2018, usage at the natural gas distribution systems totaled 34,594,000 MMBTU as compared to 30,293,000 MMBTU during the same period in 2017, an increase of 4,301,000 MMBTU or 14.2%. The increase is primarily due to higher heating degree days at the Midstates, Peach State and Empire Gas Systems.

Water and Wastewater Distribution Systems

	Three Months Ended December 31		Twelve Months Ended December 31	
	2018	**2017**	**2018**	**2017**
Average Active Connections For The Period				
Wastewater connections	**43,000**	41,400	**42,200**	41,000
Water distribution connections	**113,200**	111,800	**112,800**	121,400
Total Average Active Connections For The Period	**156,200**	153,200	**155,000**	162,400
Gallons Provided				
Wastewater treated (millions of gallons)	**606**	555	**2,282**	2,226
Water provided (millions of gallons)	**3,655**	3,909	**15,823**	16,905
Total Gallons Provided	**4,261**	4,464	**18,105**	19,131

During the three months ended December 31, 2018, the water and wastewater distribution systems provided approximately 3,655 million gallons of water to its customers and treated approximately 606 million gallons of wastewater as compared to 3,909 million gallons of water provided and 555 million gallons of wastewater treated during the same period in 2017.

During the twelve months ended December 31, 2018, the water and wastewater distribution systems provided approximately 15,823 million gallons of water to its customers and treated approximately 2,282 million gallons of wastewater as compared to 16,905 million gallons of water and 2,226 million gallons of wastewater during the same period in 2017. The decrease in the gallons of water provided to customers can be attributed to the disposition of the Mountain Water System in Montana in the second quarter of 2017. Excluding the Mountain Water System, the volumes of water provided to customers were relatively flat year-over-year.

2018 Liberty Utilities Group Operating Results

	Three Months Ended December 31		Twelve Months Ended December 31	
	2018	**2017**	**2018**	**2017**
Revenue				
Utility electricity sales and distribution	**$ 193.2**	$ 187.0	**$ 831.2**	$ 763.5
Less: cost of sales – electricity	**(63.4)**	(51.6)	**(265.1)**	(222.4)
Net Utility Sales - electricity[1]	**129.8**	135.4	**566.1**	541.1
Utility natural gas sales and distribution	**115.5**	108.0	**395.5**	344.2
Less: cost of sales – natural gas	**(59.0)**	(53.1)	**(183.0)**	(141.7)
Net Utility Sales - natural gas[1]	**56.5**	54.9	**212.5**	202.5
Utility water distribution & wastewater treatment sales and distribution	**30.4**	31.5	**128.4**	140.1
Less: cost of sales – water	**(2.1)**	(2.4)	**(8.8)**	(9.5)
Net Utility Sales - water distribution & wastewater treatment[1]	**28.3**	29.1	**119.6**	130.6
Gas transportation	**10.4**	9.6	**33.4**	31.2
Other revenue	**4.8**	5.1	**11.6**	11.8
Net Utility Sales[1]	**229.8**	234.1	**943.2**	917.2
Operating expenses	**(99.0)**	(92.4)	**(401.5)**	(383.4)
Other income	**1.5**	1.4	**5.6**	4.2
HLBV[2]	**0.6**	1.3	**3.2**	6.2
Divisional Operating Profit[1,3]	**$ 132.9**	$ 144.4	**$ 550.5**	$ 544.2

1 See *Non-GAAP Financial Measures*.

2 HLBV income represents the value of net tax attributes earned by the Liberty Utilities Group in the period primarily from electricity generated at the Luning Solar Facility.

3 Certain prior year items have been reclassified to conform with current year presentation.

2018 Fourth Quarter Operating Results

For the three months ended December 31, 2018, the Liberty Utilities Group reported an operating profit (excluding corporate administration expenses) of $132.9 million as compared to $144.4 million for the comparable period in the prior year.

Highlights of the changes are summarized in the following table:

(all dollar amounts in $ millions)	Three Months Ended December 31
Prior Period Operating Profit	**$ 144.4**
Existing Facilities	
Electricity: Decrease is primarily due to higher commodity costs combined with higher operating costs at the Empire and Granite State Electric Systems.	(10.3)
Gas: Increase is primarily due to operating cost savings at the New England Gas System.	3.2
Water: Decrease is primarily due to increase in operating costs at the Arizona and Whitehall Water Systems.	(0.1)
Other	(0.9)
	(8.1)
Rate Reviews	
Electricity: Implementation of lower rates at the Granite State and Empire Electric Systems due to U.S. Tax reform, partially offset by rate increases at the Calpeco Electric System.	(4.4)
Gas: Implementation of new rates, net of U.S. Tax Reform impact, primarily at Midstates and EnergyNorth Gas Systems.	1.7
Water: Implementation of lower rates at the Arizona and Park Water Systems due to U.S. Tax Reform.	(0.7)
	(3.4)
Current Period Divisional Operating Profit[1]	**$ 132.9**

[1] See *Non-GAAP Financial Measures.*

2018 Annual Operating Results

For the twelve months ended December 31, 2018, the Liberty Utilities Group reported an operating profit (excluding corporate administration expenses) of $550.5 million as compared to $544.2 million for the comparable period in the prior year.

Highlights of the changes are summarized in the following table:

(all dollar amounts in $ millions)		Twelve Months Ended December 31
Prior Period Operating Profit	$	**544.2**
Existing Facilities		
Electricity: Increase is primarily due to higher heating degree days in the first and fourth quarters and higher cooling degree days in the second & third quarters of the year, which resulted in higher consumption at the Empire Electric System, partially offset by an increase in operating costs.		8.9
Gas: Increase is primarily due to favourable weather resulting in higher consumption at the Empire Gas and New England Gas Systems, partially offset by an increase in operating costs at the EnergyNorth Gas System.		2.5
Water: Decrease is primarily due to lower revenue resulting from the disposition of the Mountain Water System in Montana as well as higher operating costs.		(6.0)
Other		0.5
		5.9
Rate Reviews		
Electricity: Implementation of lower rates at the Empire Electric System due to U.S. Tax Reform, partially offset by rate increases at the Calpeco Electric System.		(3.7)
Gas: Implementation of new rates, net of U.S. Tax Reform impact, primarily at the Midstates and EnergyNorth Gas Systems.		5.4
Water: Implementation of lower rates at the Arizona and Park Water Systems due to U.S. Tax Reform.		(1.3)
		0.4
Current Period Divisional Operating Profit[1]	$	**550.5**

1 See *Non-GAAP Financial Measures*.

Regulatory Proceedings

The following table summarizes the major regulatory proceedings currently underway within the Liberty Utilities Group:

Utility	State	Regulatory Proceeding Type	Rate Request (millions)	Current Status
Completed Rate Reviews				
EnergyNorth Gas System	New Hampshire	General Rate Case ("GRC")	$19.5	In April 2018, an Order was issued approving a full revenue decoupling mechanism and an immediate revenue increase of $13.1 million effective May 1, 2018 and the ability to collect an additional $0.4 million in the cost of gas filing. In total, this represents revenue increases of $13.5 million. Concurrent with the implementation of these new rates, the New Hampshire Public Utilities Commission ("NHPUC") also ordered a reduction in rates of $2.4 million resulting from U.S. Tax Reform which will be reflected in EnergyNorth's future rates effective May 1, 2018, bringing the net rate increase to $11.1 million.
New England Gas	Massachusetts	Gas System Enhancement Plan ("GSEP")	$5.8	Final Order issued in April 2018 approving a $3.7 million rate increase effective May 1, 2018.
Missouri Gas System	Missouri	GRC	$6.0	Final Order issued in June 2018 approving a $4.6 million rate increase effective July 1, 2018 and a revenue decoupling mechanism for residential and small commercial customers.
Peach State Gas System	Georgia	GRAM	$2.4	On January 31, 2019, an Order was issued approving an increase in revenue of $2.4 million for rates effective February 1, 2019.
Empire Electric System	Missouri	Tax Cuts and Jobs Act of 2017	-$17.8	Prospective decrease in annual revenue of $17.8 million due to U.S. Tax Reform beginning August 30, 2018.
Various	Various	Various	$4.8	Rate reviews closed in 2018 with a combined approved rate increase of $3.0 million include: Park Water 2018 increase, Georgia Gas Rate Adjustment Mechanism, Missouri Water System, and Litchfield Park Water & Sewer.
Pending Rate Reviews				
CalPeco Electric	California	GRC	$6.7	On December 3, 2018, filed a three year application requesting a rate increase of $6.7 million for 2019 ($5.9 million for 2020 and $3.8 million for 2021).
Empire Electricity (Kansas System)	Kansas	GRC	$2.5	On December 7, 2018, filed an application requesting an incremental increase in revenue requirement of $2.5 million.
New England Natural Gas System	Massachusetts	GSEP	$3.8	On October 31, 2018, filed for an incremental increase in revenue requirement of $3.8 million for the 2019 GSEP.
Various	Various	Various	$3.9	Other pending rate review requests include: Woodmark/Tall Timbers Wastewater Systems ($1.6 million), Silverleaf Texas Water and Wastewater Systems ($1.3 million), and Apple Valley and Park Water Systems ($1.0 million).

Completed Rate Reviews

New Hampshire

On April 28, 2017, the Liberty Utilities Group filed a distribution rate application with the NHPUC, for rates to be effective May 1, 2018, seeking a total revenue increase of $19.5 million with approximately $14.5 million based on a test year ending December 31, 2016 plus a step increase of approximately $5.0 million. Temporary rates of $7.8 million to be effective July 1, 2017, and full revenue decoupling from the impacts of weather were requested. On June 30, 2017, the NHPUC approved temporary rates of $6.8 million effective July 1, 2017 to be in place until the end of the permanent rate case. On April 27, 2018, the NHPUC issued its Order approving a full revenue decoupling mechanism and an immediate revenue increase of $13.1 million effective May 1, 2018 and the ability to collect an additional $0.4 million in the cost of gas filing. In total, this represents revenue increases of $13.5 million (70% of the requested increase amount). Concurrent with the implementation of these new rates, the NHPUC has also ordered a reduction in rates of $2.4 million resulting from U.S. Tax Reform which will be reflected in the EnergyNorth Gas System's future rates effective May 1, 2018, bringing the net rate increase to $11.1 million. The order also authorizes an ROE of 9.3% and an additional one-time, $1.3 million recoupment to be collected from customers to make whole the difference between the permanent rates and the temporary rates authorized on July 1, 2017. In May 2018, EnergyNorth filed a motion for rehearing to clarify the implementation date of the decoupling mechanism that was approved. In addition, the NHPUC resolved the impacts of tax reform through the rehearing instead of addressing it in a separate hearing. The net result was a one-time decrease in revenue of $0.3 million.

Massachusetts

On October 31, 2017, Liberty Utilities (New England Natural Gas Company) Corp. filed its 2018 GSEP application requesting recovery of $6.2 million for replacement of approximately 14 miles of eligible infrastructure. In March 2018, the revenue requirement was revised to $5.8 million. On April 30, 2018 an order was issued authorizing the recovery of $3.7 million. The revenue increase is not affected by U.S. Tax Reform but is expected to be addressed in the 2019 filing.

Missouri

On September 29, 2017, Liberty Utilities (Midstates Natural Gas) Corp. filed an application seeking a rate increase of $7.5 million for test year ending June 30, 2017 with proforma adjustments through to March 31, 2018. In April 2018, the revenue requirement request was revised to $6.0 million. An order was issued on June 6, 2018 authorizing an annual revenue increase of $4.6 million, a 9.8% ROE, and also incorporates the effects of U.S. Tax Reform. The order contemplates that new rates will go into effect on July 1, 2018. In addition, it adopts rate consolidation for the NEMO and WEMO districts, and allows the Liberty Utilities Group to adopt a Weather Normalization Adjustment Rider designed to adjust the Company’s rates for the impact of weather on customer usage.

On July 12, 2018, Empire received an order from the MPSC supporting various requests related to its proposed Customer Savings Plan, which calls for the development of up to 600 MW of sustainable, cost-effective wind power to serve the needs of electricity customers within the Liberty Utilities Group's Midwest electric service territory. The order allows the Liberty Utilities Group to continue to pursue the development of up to 600 MW of wind and recognizes that “millions of dollars of customer savings could be of considerable benefit to Empire’s customers and the entire state”. In addition, regulatory proceedings in other jurisdictions will be completed as necessary. The Company has filed CCN applications with the MPSC for the North Fork Ridge, Kings Point and Neosho Ridge Wind Projects and a final hearing has been scheduled for April 2019. The Company has also filed a CCN application with the Kansas Corporation Commission for the gen-tie line associated with the Neosho Ridge Wind Project.

2018 Electricity Generation Performance

(Performance in GW-hrs sold)	Long Term Average Resource	Three Months Ended December 31 2018	Three Months Ended December 31 2017	Long Term Average Resource	Twelve Months Ended December 31 2018	Twelve Months Ended December 31 2017
Hydro Facilities:						
Maritime Region	**37.6**	**31.4**	34.9	**148.2**	**107.5**	129.7
Quebec Region	**72.6**	**73.6**	67.5	**273.3**	**263.7**	270.6
Ontario Region	**26.2**	**31.3**	30.6	**120.4**	**106.5**	129.5
Western Region	**12.6**	**11.2**	10.5	**65.0**	**59.8**	59.6
	149.0	**147.5**	143.5	**606.9**	**537.5**	589.4
Wind Facilities:						
St. Damase	**22.7**	**22.2**	24.0	**76.9**	**78.8**	74.3
St. Leon	**121.4**	**101.4**	138.7	**430.2**	**394.8**	444.2
Red Lily[1]	**24.1**	**20.0**	29.2	**88.5**	**81.3**	91.6
Morse	**30.5**	**26.2**	33.1	**108.8**	**96.8**	106.4
Amherst[2]	**67.9**	**58.7**	—	**118.5**	**105.7**	—
Sandy Ridge	**43.6**	**43.8**	42.0	**158.3**	**152.2**	153.3
Minonk	**189.8**	**173.8**	203.5	**673.7**	**611.3**	673.7
Senate	**140.0**	**125.2**	126.6	**520.4**	**484.9**	492.8
Shady Oaks	**100.5**	**91.5**	108.7	**355.6**	**326.6**	365.5
Odell	**238.0**	**199.9**	244.6	**831.8**	**759.4**	807.2
Deerfield[3]	**167.9**	**153.8**	164.3	**546.0**	**531.2**	449.3
	1,146.4	**1,016.5**	1,114.7	**3,908.7**	**3,623.0**	3,658.3
Solar Facilities:						
Cornwall	**2.2**	**1.8**	2.1	**14.7**	**14.5**	14.4
Bakersfield	**13.0**	**9.5**	12.7	**77.2**	**70.0**	70.5
Great Bay Solar[4]	**25.7**	**26.4**	—	**115.6**	**110.6**	—
	40.9	**37.7**	14.8	**207.5**	**195.1**	84.9
Renewable Energy Performance	**1,336.3**	**1,201.7**	1,273.0	**4,723.1**	**4,355.6**	4,332.6
Thermal Facilities:						
Windsor Locks	**N/A[5]**	**46.1**	31.8	**N/A[5]**	**154.7**	122.0
Sanger	**N/A[5]**	**11.3**	33.5	**N/A[5]**	**146.4**	86.0
		57.4	65.3		**301.1**	208.0
Total Performance		**1,259.1**	1,338.3		**4,656.7**	4,540.6

1 APUC owns a 75% equity interest in the Red Lily Wind Facility but accounts for the facility using the equity method. The production figures represent full energy produced by the facility.

2 APUC owns a 50% equity interest in the Amherst Wind Facility. The Amherst Wind Facility achieved COD on June 15, 2018 in accordance with the terms of the PPA, however, the facility was partially operational prior to that date. The production data includes all energy produced during the year.

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 production noted above represents all production from the date of COD.

4 The Great Bay Solar Facility achieved COD on March 29, 2018 in accordance with the terms of the PPA, however, the facility was partially operational prior to that date. The production data includes all energy produced during the year.

5 Natural gas fired co-generation facility.

2018 Fourth Quarter Liberty Power Group Performance

For the three months ended December 31, 2018, the Liberty Power Group generated 1,259.1 GW-hrs of electricity as compared to 1,338.3 GW-hrs during the same period of 2017.

For the three months ended December 31, 2018, the hydro facilities generated 147.5 GW-hrs of electricity as compared to 143.5 GW-hrs produced in the same period in 2017, an increase of 2.8%. Electricity generated represented 99.0% of long-term average resources ("LTAR") as compared to 92.8% during the same period in 2017. During the quarter, all regions except the Maritime Region were above their respective LTAR.

For the three months ended December 31, 2018, the wind facilities produced 1,016.5 GW-hrs of electricity as compared to 1,114.7 GW-hrs produced in the same period in 2017, a decrease of 8.8%. During the three months ended December 31, 2018, the wind facilities (excluding the Amherst Wind Facility) generated electricity equal to 88.8% of LTAR as compared to 103.3% during the same period in 2017 primarily due to lower wind resource.

For the three months ended December 31, 2018, the solar facilities generated 37.7 GW-hrs of electricity as compared to 14.8 GW-hrs of electricity in the same period in 2017, an increase of 154.7%. The increase in production is primarily due to the addition of the Great Bay Solar Facility which achieved full COD on March 29, 2018. The solar facilities (excluding the Great Bay Solar Facility) production was 25.7% below its LTAR as compared to 2.6% below in the same period in 2017 primarily due to lower irradiance.

For the three months ended December 31, 2018, the thermal facilities generated 57.4 GW-hrs of electricity as compared to 65.3 GW-hrs of electricity during the same period in 2017. During the same period, the Windsor Locks Thermal Facility generated 145.7 billion lbs of steam as compared to 136.9 billion lbs of steam during the same period in 2017.

2018 Annual Liberty Power Group Performance

For the twelve months ended December 31, 2018, the Liberty Power Group generated 4,656.7 GW-hrs of electricity as compared to 4,540.6 GW-hrs during the same period of 2017.

For the twelve months ended December 31, 2018, the hydro facilities generated 537.5 GW-hrs of electricity as compared to 589.4 GW-hrs produced in the same period in 2017, a decrease of 8.8%. Electricity generated represented 88.6% of LTAR as compared to 94.7% during the same period in 2017. The decrease is primarily due to reduced hydrology in the Maritime and Ontario Regions.

For the twelve months ended December 31, 2018, the wind facilities produced 3,623.0 GW-hrs of electricity as compared to 3,658.3 GW-hrs produced in the same period in 2017, a decrease of 1.0%. During the twelve months ended December 31, 2018, the wind facilities generated electricity equal to 92.7% of LTAR as compared to 98.7% during the same period in 2017. The decrease in production was partially offset by higher production at the St. Damase Wind Facility as well as the incremental electricity generated at the Deerfield and Amherst Wind Facilities which achieved COD on February 21, 2017 and June 15, 2018, respectively.

For the twelve months ended December 31, 2018, the solar facilities generated 195.1 GW-hrs of electricity as compared to 84.9 GW-hrs of electricity produced in the same period in 2017, an increase of 129.8%. The increase in production is primarily due to the addition of the Great Bay Solar Facility which achieved full COD on March 29, 2018. The solar facilities (excluding the Great Bay Solar Facility) production was 8.1% below its LTAR as compared to 7.6% below in the same period in 2017.

For the twelve months ended December 31, 2018, the thermal facilities generated 301.1 GW-hrs of electricity as compared to 208.0 GW-hrs of electricity during the same period in 2017. During the same period, the Windsor Locks Thermal Facility generated 566.9 billion lbs of steam as compared to 559.1 billion lbs of steam during the same period in 2017.

2018 Liberty Power Group Operating Results

(all dollar amounts in $ millions)	Three Months Ended December 31		Twelve Months Ended December 31	
	2018	2017	2018	2017
Revenue[1]				
Hydro	**$ 11.7**	$ 11.0	**$ 42.6**	$ 44.7
Wind	**37.7**	42.5	**133.5**	132.1
Solar	**2.8**	1.6	**17.2**	10.8
Thermal	**10.2**	8.8	**42.1**	30.0
Total Revenue	**$ 62.4**	$ 63.9	**$ 235.4**	$ 217.6
Less:				
Cost of Sales - Energy[2]	**(1.4)**	(1.5)	**(5.5)**	(5.1)
Cost of Sales - Thermal	**(5.1)**	(4.6)	**(21.7)**	(14.5)
Realized gain/(loss) on hedges[3]	**0.1**	—	**0.1**	(0.7)
Net Energy Sales[8]	**$ 56.0**	$ 57.8	**$ 208.3**	$ 197.3
Renewable Energy Credits ("REC")[4]	**2.7**	4.3	**11.0**	13.2
Other Revenue	**0.4**	0.1	**0.9**	0.4
Total Net Revenue	**$ 59.1**	$ 62.2	**$ 220.2**	$ 210.9
Expenses & Other Income				
Operating expenses	**(13.2)**	(17.3)	**(71.0)**	(66.9)
Interest, dividend, equity and other income[5]	**18.3**	0.9	**45.7**	2.9
HLBV income[6]	**14.5**	9.9	**108.7**	45.9
Divisional Operating Profit[7,8]	**$ 78.7**	$ 55.7	**$ 303.6**	$ 192.8

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 *Note 23(b)(iv)* in the annual audited consolidated financial statements.

4 Qualifying renewable energy projects receive RECs for the generation and delivery of renewable energy to the power grid. The energy credit certificates represent proof that 1 MW of electricity was generated from an eligible energy source.

5 Includes dividends received from Atlantica of which APUC owns approximately 41.5% of the common shares (see *Note 8* in the annual audited consolidated financial statements).

6 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.

7 Certain prior year items have been reclassified to conform to current year presentation.

8 See *Non-GAAP Financial Measures*.

2018 Fourth Quarter Operating Results

For the three months ended December 31, 2018, the Liberty Power Group's facilities generated $78.7 million of operating profit as compared to $55.7 million during the same period in 2017, which represents an increase of $23.0 million or 41.3%, 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	**$**	**55.7**
Existing Facilities		
Hydro: Increase is primarily due to higher production and favourable rates in the Western Region, partially offset by unfavourable rates in the Maritime Region.		0.9
Wind Canada: Decrease is primarily due to lower production.		(2.5)
Wind U.S.: Decrease is primarily due to lower production, partially offset by higher HLBV income at the Deerfield Wind Facility.		(1.7)
Solar Canada: Decrease is primarily due to lower production.		(0.1)
Solar U.S.: Decrease is primarily due to a change in HLBV income assumptions as a result of U.S. Tax Reform.		(1.1)
Thermal: Increase is primarily due to higher overall production as well as an increase in capacity revenue at the Windsor Locks Thermal Facility earned through the second phase of a contract that began in 2018, partially offset by an increase in fuel costs.		0.3
Other: Increase is primarily due higher dividend and equity income.		4.8
		0.6
New Facilities and Investments		
Solar U.S.: Great Bay Solar reached full COD in March 2018.		4.7
Wind Canada: Amherst Island Wind Facility interest and equity income received as it achieved COD in June 2018.		2.7
Atlantica & AAGES: Dividends from Atlantica, net of AAGES equity loss.		15.6
		23.0
Foreign Exchange		**(0.6)**
Current Period Divisional Operating Profit[1]	**$**	**78.7**

1 See *Non-GAAP Financial Measures*.

2018 Annual Operating Results

For the twelve months ended December 31, 2018, the Liberty Power Group's facilities generated $303.6 million of operating profit as compared to $192.8 million during the same period in 2017, which represents an increase of $110.8 million or 57.5%, 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	**$**	**192.8**
Existing Facilities		
Hydro: Decrease is primarily due to lower production and the recognition of a bonus payment from Hydro Quebec in the prior year, partially offset by favourable rates in the Western Region.		(2.5)
Wind Canada: Decrease is primarily due to lower overall production		(2.6)
Wind U.S.: Increase is primarily due to HLBV income acceleration resulting from U.S. Tax Reform[1], partially offset by lower production.		41.6
Solar Canada: Increase is primarily due to higher production.		0.1
Thermal: Increase is primarily due to higher overall production as well as an increase in capacity revenue at the Windsor Locks Thermal Facility earned through the second phase of a contract that began in 2018, partially offset by an increase in fuel costs.		3.5
Other: Increase is primarily due higher dividend and equity income.		4.9
		45.0
New Facilities and Investments		
Wind U.S.: Acquisition of Deerfield Wind Facility in March 2017.		13.5
Solar U.S.: Great Bay Solar achieved full COD in March 2018.		10.7
Wind Canada: Amherst Island Wind Facility interest and equity income received as it achieved COD in June 2018.		4.3
Atlantica & AAGES: Dividends from Atlantica, net of AAGES equity loss.		37.4
		65.9
Foreign Exchange		**(0.1)**
Current Period Divisional Operating Profit[2]	**$**	**303.6**

1 As a result of U.S. Tax Reform, the differential membership interests associated with the Company's renewable energy projects in the U.S. that utilized tax equity were remeasured. This remeasurement resulted in an acceleration of income associated with HLBV in the amount of $55.9 million for the existing Wind U.S. and Solar U.S. facilities at the Liberty Power Group. Over the remaining life of existing tax equity structures of APUC, U.S. Tax Reform on balance has not materially affected, either positively or negatively, the economic benefits of the underlying tax equity structures in total.

2 See *Non-GAAP Financial Measures*.

APUC: CORPORATE AND OTHER EXPENSES

(all dollar amounts in $ millions)	Three Months Ended December 31 2018	Three Months Ended December 31 2017	Twelve Months Ended December 31 2018	Twelve Months Ended December 31 2017
Corporate and other expenses:				
Administrative expenses	**$ 15.0**	$ 14.7	**$ 52.7**	$ 49.6
Loss (gain) on foreign exchange	**0.7**	1.3	**(0.1)**	0.3
Interest expense on convertible debentures and costs related to acquisition financing	**—**	—	**—**	13.4
Interest expense	**40.3**	33.4	**152.1**	142.4
Depreciation and amortization	**63.8**	69.2	**260.8**	251.3
Change in value of investment carried at fair value	**46.0**	—	**138.0**	—
Interest, dividend, equity, and other loss (income)[1]	**(0.4)**	(0.5)	**(1.8)**	(2.2)
Pension and post-employment non-service costs[2]	**1.4**	2.5	**3.9**	9.0
Other losses	**2.3**	3.7	**2.7**	0.7
Acquisition-related costs, net	**(8.9)**	1.0	**0.7**	47.7
Loss (gain) on derivative financial instruments	**(0.3)**	(3.1)	**0.6**	(1.9)
Income tax expense	**2.8**	29.7	**53.4**	73.4

1 Excludes income directly pertaining to the Liberty Power and Liberty Utilities Groups (disclosed in the relevant sections).

2 Pension amounts previously noted as part of operating expenses. See *Note 10* in the annual audited consolidated financial statements for further details.

2018 Fourth Quarter Corporate and Other Expenses

During the three months ended December 31, 2018, administrative expenses totaled $15.0 million as compared to $14.7 million in the same period in 2017.

For the three months ended December 31, 2018, interest expense totaled $40.3 million as compared to $33.4 million in the same period in 2017. The increase is primarily due to drawings under the Corporate Term Facility and issuance of Fixed-to-Floating Subordinated Notes in October 2018, partially offset by debt maturities.

For the three months ended December 31, 2018, depreciation expense totaled $63.8 million as compared to $69.2 million in the same period in 2017. The decrease is primarily due to a one-time adjustment due to regulatory proceedings.

For the three months ended December 31, 2018, change in investment carried at fair value totaled $46.0 million as compared to $nil in 2017. The 2018 change in fair value reflects an unrealized loss related to the investment in Atlantica (see *Note 8* in the annual audited consolidated financial statements).

For the three months ended December 31, 2018, pension and post-employment non-service costs totaled $1.4 million as compared to $2.5 million in 2017.

For the three months ended December 31, 2018, other losses were $2.3 million as compared to $3.7 million in the same period in 2017. The loss in 2018 mainly relates to the write down of notes receivables and costs from condemnation proceedings. The loss in 2017 was 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, 2018, acquisition related cost recovery totaled $8.9 million as compared to an expense of $1.0 million in 2017. The decrease is primarily due to a settlement related to the Shady Oaks Wind Facility acquisition.

For the three months ended December 31, 2018, gains on derivative financial instruments totaled $0.3 million as compared to $3.1 million in the same period in 2017. The gains in 2017 were primarily driven by mark-to-market gains on commodity derivatives.

For the three months ended December 31, 2018, an income tax expense of $2.8 million was recorded as compared to an income tax expense of $29.7 million during the same period in 2017. The decrease in income tax expense is primarily due to U.S. Tax Reform (see *U.S. Tax Reform* for additional information).

2018 Annual Corporate and Other Expenses

During the twelve months ended December 31, 2018, administrative expenses totaled $52.7 million as compared to $49.6 million in the same period in 2017. The increase primarily relates to additional costs incurred to administer APUC's operations as a result of the Company's growth.

For the twelve months ended December 31, 2018, interest expense on convertible debentures and bridge financing totaled $nil as compared to $13.4 million in the same period in 2017. The 2017 expense related to non-recurring financing costs related to the acquisition of Empire, as well as interest expense on convertible debentures before conversion to common shares in the first quarter of 2017.

For the twelve months ended December 31, 2018, interest expense totaled $152.1 million as compared to $142.4 million in the same period in 2017. The increase is primarily due to drawings under the Corporate Term Facility and issuance of Fixed-to-Floating Subordinated Notes in October 2018, partially offset by debt maturities.

For the twelve months ended December 31, 2018, depreciation expense totaled $260.8 million as compared to $251.3 million in the same period in 2017. The increase is primarily due to an increase in property, plant and equipment.

For the twelve months ended December 31, 2018, change in investment carried at fair value totaled $138.0 million as compared to $nil in the same period in 2017. The 2018 change in fair value reflects an unrealized loss related to the investment in Atlantica (see *Note 8* in the annual audited consolidated financial statements).

For the twelve months ended December 31, 2018, pension and post-employment non-service costs totaled $3.9 million as compared to $9.0 million in the same period in 2017. The decrease is primarily due to a higher return on plan assets in 2018.

For the twelve months ended December 31, 2018, other losses were $2.7 million as compared to a loss of $0.7 million in the same period in 2017. The loss in 2018 mainly relates to the write down of notes receivables and costs from condemnation proceedings. The prior period loss is primarily related to the write-off of rate review expenses for several water utilities, partially offset by the disposition of the Mountain Water utility.

For the twelve months ended December 31, 2018, acquisition-related costs totaled $0.7 million as compared to $47.7 million in the same period in 2017. The costs in 2018 primarily related to the investment in Atlantica, partially offset by a settlement related to the Shady Oaks Wind Facility acquisition. The costs in 2017 primarily related to the acquisition of Empire.

For the twelve months ended December 31, 2018, the loss on derivative financial instruments totaled $0.6 million as compared to a gain of $1.9 million in the same period in 2017. The gain in 2017 was primarily due to mark-to-market gains on commodity derivatives. The loss in 2018 is primarily due to the ineffective portion related to the extension of the Liberty Power Group's interest rate hedge on expected debt financing.

An income tax expense of $53.4 million was recorded in the twelve months ended December 31, 2018 as compared to an income tax expense of $73.4 million during the same period in 2017. The decrease in income tax expense is primarily due to U.S. Tax Reform (see *U.S. Tax Reform* for additional information).

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 among other things, reduced the U.S. federal corporate income tax rate from 35% to 21% effective January 1, 2018. As a result, in the fourth quarter of 2017, the Company was required to revalue its U.S. deferred income tax assets and liabilities based on the new tax rate. This remeasurement resulted in a non-cash accounting charge of $17.1 million which was recorded in the Company's 2017 consolidated statement of operations.

In 2018, the Company completed its remeasurement of deferred income tax assets and liabilities as permitted under the measurement period outlined under SEC Staff Accounting Bulletin 118, Income Tax Accounting Implications of the Tax Cuts and Jobs Act ("SAB 118"). The final adjustments related to the implementation of U.S. Tax Reform resulted in a non-cash accounting benefit of $18.4 million which was recorded in the Company's 2018 consolidated statement of operations.

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)	**2018**	**2017**	**2018**	**2017**
Net earnings attributable to shareholders	**$ 44.0**	$ 47.2	**$ 185.0**	$ 149.5
Add (deduct):				
Net earnings attributable to the non-controlling interest, exclusive of HLBV	**3.4**	0.6	**4.8**	2.4
Income tax expense	**2.8**	29.7	**53.4**	73.4
Interest expense on convertible debentures and costs related to acquisition financing	**—**	—	**—**	13.4
Interest expense on long-term debt and others	**40.3**	33.3	**152.1**	142.4
Other losses	**2.3**	3.8	**2.7**	0.7
Acquisition-related costs	**(8.9)**	1.0	**0.7**	47.7
Pension and post-employment non-service costs[1]	**1.4**	2.5	**3.9**	9.0
Change in value of investment in Atlantica carried at fair value	**46.0**	—	**138.0**	—
Costs related to tax equity financing	**1.3**	0.4	**1.3**	1.8
Loss (gain) on derivative financial instruments	**(0.3)**	(3.1)	**0.6**	(1.9)
Realized (loss) gain on energy derivative contracts	**0.1**	—	**0.1**	(0.6)
Loss (gain) on foreign exchange	**0.7**	1.2	**(0.1)**	0.3
Depreciation and amortization	**63.8**	69.2	**260.8**	251.3
Adjusted EBITDA	**$ 196.9**	$ 185.8	**$ 803.3**	$ 689.4

1 As a result of adoption of ASU 2017-07 certain components of net benefit pension costs are considered non-service costs and are now classified outside of operating income (see *Note 2(a)* in the annual audited consolidated financial statements).

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, 2018 amounted to $13.8 million and $110.7 million as compared to $11.3 million and $52.1 million during the same period in 2017. In the first quarter of 2018 a one-time acceleration of HLBV income in the amount of $55.9 million was recorded as a result of U.S. Tax Reform.

Reconciliation of Adjusted 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)	2018	2017	2018	2017
Net earnings attributable to shareholders	**$ 44.0**	$ 47.2	**$ 185.0**	$ 149.5
Add (deduct):				
Loss (gain) on derivative financial instruments	**(0.3)**	(3.1)	**0.6**	(1.9)
Realized (loss) gain on energy derivative contracts	**0.1**	—	**0.1**	(0.6)
Loss (gain) on long-lived assets, net	**1.9**	1.2	**0.8**	(1.8)
Loss (gain) on foreign exchange	**0.7**	1.2	**(0.1)**	0.3
Interest expense on convertible debentures and costs related to acquisition financing	**—**	—	**—**	13.4
Acquisition-related costs	**(8.9)**	1.0	**0.7**	47.7
Change in value of investment in Atlantica carried at fair value	**46.0**	—	**138.0**	—
Costs related to tax equity financing	**1.3**	0.4	**1.3**	1.8
Other adjustments	**—**	2.5	**—**	2.5
U.S. Tax Reform and related deferred tax adjustments[1]	**(18.4)**	17.1	**(18.4)**	17.1
Adjustment for taxes related to above	**4.1**	(0.5)	**4.2**	(3.0)
Adjusted Net Earnings	**$ 70.5**	$ 67.0	**$ 312.2**	$ 225.0
Adjusted Net Earnings per share[2]	**$ 0.14**	$ 0.16	**$ 0.66**	$ 0.57

1 Represents the non-cash accounting charge related to the revaluation of U.S. deferred income tax assets and liabilities as a result of implementation of the effects of U.S. Tax Reform (see *U.S. Tax Reform* for additional information).

2 Per share amount calculated after preferred share dividends and excluding subscription receipts issued for projects or acquisitions not reflected in earnings.

For the three months ended December 31, 2018, Adjusted Net Earnings totaled $70.5 million as compared to Adjusted Net Earnings of $67.0 million for the same period in 2017, an increase of $3.5 million.

For the twelve months ended December 31, 2018, Adjusted Net Earnings totaled $312.2 million as compared to Adjusted Net Earnings of $225.0 million for the same period in 2017, an increase of $87.2 million.

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:

(all dollar amounts in $ millions)	Three Months Ended December 31 2018	Three Months Ended December 31 2017	Twelve Months Ended December 31 2018	Twelve Months Ended December 31 2017
Cash flows from operating activities	**$ 168.6**	$ 116.0	**$ 530.4**	$ 326.6
Add (deduct):				
Changes in non-cash operating items	**(27.3)**	9.1	**8.1**	87.7
Production based cash contributions from non-controlling interests	**—**	—	**13.9**	7.9
Interest expense on convertible debentures and costs related to acquisition financing[1]	**—**	—	**—**	7.2
Acquisition-related costs	**(8.8)**	0.9	**0.7**	47.7
Reimbursement of operating expenses incurred on joint venture	**—**	—	**1.0**	—
Adjusted Funds from Operations	**$ 132.5**	$ 126.0	**$ 554.1**	$ 477.1

[1] Exclusive of deferred financing fees of $6.2 million.

For the three months ended December 31, 2018, Adjusted Funds from Operations totaled $132.5 million as compared to Adjusted Funds from Operations of $126.0 million for the same period in 2017, an increase of $6.5 million.

For the twelve months ended December 31, 2018, Adjusted Funds from Operations totaled $554.1 million as compared to Adjusted Funds from Operations of $477.1 million for the same period in 2017, an increase of $77.0 million.

CORPORATE DEVELOPMENT ACTIVITIES

The Company's worldwide development activities for projects either owned directly by the Company or indirectly through AAGES entities are undertaken primarily by AAGES, a joint venture formed with Abengoa. AAGES and its affiliates work with a global reach to identify, develop, and construct new renewable power generating facilities, power transmission lines and water infrastructure assets. Once a project developed by AAGES has reached commercial operation, a determination will be made on whether it will be optimal for such project to be held by APUC, remain in AAGES, or be offered for sale to Atlantica or, in limited circumstances, another party.

The Company has an identified development pipeline of approximately $4.0 billion over the next 5 years consisting of potential investments in $1.4 billion in North American regulated renewable generation assets, $1.7 billion of North American unregulated renewable generation assets, $0.4 billion in regulated electric and gas transmission assets and $0.5 billion in international development projects.

The projects identified are at various stages of development, and have advanced to a stage where the resolutions to major project uncertainties such as regulatory approvals, land control, economic and other contractual issues are probable, but not certain, and it is expected that the project will meet management's risk adjusted return expectations.

Projects Completed

Great Bay Solar Project

The Great Bay Solar Project is a 75 MW solar powered electric generating facility comprising four sites located in Somerset County in southern Maryland.

The facility is composed of 300,000 solar panels and is located 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 achieved commercial operation in two phases: 20 MW on December 30, 2017 and 55 MW on March 29, 2018.

Amherst Island Wind Project

The Amherst Island Wind Project is a 75 MW wind powered electric generating facility located on Amherst Island near the village of Stella, approximately 15 kilometers southwest of Kingston, Ontario.

The project is composed of 26 Siemens 3.2 MW turbines and is expected to produce approximately 235.0 GW-hrs of electrical energy annually, with all energy being sold under a PPA awarded as part of the Independent Electricity System Operator ("IESO"), formerly the Ontario Power Authority.

During the year, the Amherst Project achieved COD, and received notice from the IESO confirming that the FIT term commenced June 15, 2018, and that the FIT contract remains in full force and effect.

During 2018, the Liberty Power Group's interest in the project was held in a joint venture with the EPC contractor; subsequent to year-end, the Liberty Power Group exercised its option to acquire, at a pre-agreed price, the balance of the joint venture interest not previously owned. The acquisition is subject to regulatory approval, which is expected to be obtained in 2019.

Projects in Construction

Turquoise Solar Project

The Turquoise Solar Project is a 10 MW solar powered electric generating development project located in Washoe County in Nevada.

The project is expected to generate 28 GW-hrs of energy per year which will be consumed by the Calpeco Electric System customers.

The Liberty Utilities Group believes that the project will qualify for U.S. federal investment tax credits. Investment in the project by the Calpeco Electric System, net of the third party tax equity investment sought to efficiently use the tax attributes from the project, has been approved by the California Public Utility Commission for inclusion in the rate base of the utility. The cost of energy from the project is forecast to result in savings to the energy costs incurred by the Calpeco Electric System customers.

The project reached mechanical completion in the fourth quarter of 2018, and commissioning is due to be completed in the first quarter of 2019.

North American Development Activities

Mid-West Wind Development Project

In 2017, the Liberty Utilities Group presented a plan to the MPSC for an investment in up to 600 MW of strategically located wind energy generation which is forecast to reduce energy costs for its customers. On July 11, 2018, an order was received from the MPSC supporting various requests related to the proposed investment plan.

Effective October 11, 2018, Empire entered into purchase agreements with a developer for two wind development projects, North Fork Ridge and Kings Point, and effective November 16, 2018, entered into a third purchase agreement with another developer for Neosho Ridge, with total combined capacity of 600 MW. The agreements contain development milestones and termination provisions that primarily apply prior to the commencement of construction. Agreements have also been executed for the design and construction of the projects. These projects are located in Kansas and Missouri, within the Empire District Electric System service territory, and are expected to begin construction in the second half of 2019, subject to the receipt of certain regulatory approvals. The estimated construction cycle for the projects is 12 to 18 months.

The proposed new wind generating capacity is forecast to generate approximately 2,400 GW-hrs of energy per year for consumption by the Empire Electric System customers.

The development and construction costs of the three projects comprising the 600 MW plan, net of third party tax equity investment sought to efficiently use the tax attributes from the projects, are expected to be included in the rate base of the Empire Electric System. The cost of energy from the projects is forecast to result in savings to the energy costs incurred by the Empire Electric System customers.

Granite Bridge Project

The Liberty Utilities Group is developing the Granite Bridge Project, which has been conceived to help relieve supply constraints impacting the Liberty Utilities Group's natural gas distribution customers in order to reduce customer gas energy costs and support continued economic growth. The project comprises a proposed 26 mile natural gas pipeline, connecting the Portland Natural Gas Transmission System, the Maritimes & Northeast Pipeline (Joint Facilities) and the Tennessee Gas Concord Lateral, which provides service to the Liberty Utilities Groups' New Hampshire distribution system. The pipeline will be constructed in a designated energy infrastructure corridor along Route 101, and will be completely within the New Hampshire Department of Transportation ("NHDOT") right of way in New Hampshire. In addition, the project includes a proposed 2 bcf full containment storage tank and liquefaction and vaporization equipment, all of which will be located in an abandoned quarry to minimize visual impact to the host community of Epping, New Hampshire.

The Liberty Utilities Group filed for approval of its plan to construct the project with the NHPUC in December 2017, and a decision is expected in 2019.

The Liberty Utilities Group has commenced environmental, geotechnical and survey work on the project, and has received preliminary acceptance from the NHDOT on its proposed pipeline route. The Manchester, Hudson, Nashua, and Concord Chambers of Commerce have publicly endorsed the project, together with the New Hampshire Building Trades. In addition, a bipartisan group of 22 State senators has publicly endorsed the project.

The development and construction costs of the project are expected to be included in the rate base of the EnergyNorth Natural Gas System.

Final investment decision will be made following receipt of NHPUC and New Hampshire Site Evaluation Committee approvals.

Sugar Creek Wind Project

The Sugar Creek Wind Project is a 202 MW wind power electric development project located in Logan County, Illinois. Development of the project is underway. A long-term contract is in place with the Illinois Power Agency to provide renewable energy certificates from the project to utilities in the state. Energy from the project will be sold pursuant to a long-term financial hedge, which was executed in the fourth quarter of 2018 with a creditworthy counterparty. An initial agreement has been entered into to secure construction services for the project, with a definitive agreement expected during the first quarter of 2019. Initial payment has been made for project turbines for an anticipated delivery to site in the second quarter of 2020, and a turbine supply agreement for the project is expected to be signed in the first quarter of 2019. COD for the project is expected in the fourth quarter of 2020.

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 approximately 800.0 GW-hrs of energy per year, with all energy sold to SaskPower pursuant to a 25 year PPA.

Ministerial approval to proceed with the development of the project was received from the Saskatchewan Ministry of Environment. The project has also received development permits from the municipalities of Lawtonia and Morse.

Based on the recently completed system impact study for the project, the expected time frame for design and construction is estimated to be between 24 and 36 months. SaskPower has commenced the Facilities Study phase of the interconnection procedures required to connect the Blue Hill Wind Project to SaskPower's transmission system. A geotechnical evaluation of the project site including existing infrastructure and municipal roads has been completed. The current project execution plan estimates the COD date for the project to be late 2021 or early 2022.

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, near Quebec City. The Liberty Power Group holds a 50% interest in the project through a partnership created with the Val-Éo Wind Cooperative (a community based landowner consortium).

The project will be developed in two phases. Phase I of the project is expected to be completed in 2019 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-Québec Distribution 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, except for final approval from Transport Canada and an agricultural land use permit expected in the first quarter of 2019.

During the second quarter of 2018, the Liberty Power Group executed an interconnection agreement with Hydro-Québec TransÉnergie. Additionally, the Liberty Power Group executed a revised turbine supply agreement which resulted in approximately C$10 million in cost savings over the initial Phase I project cost estimates. On September 14, 2018, a service and maintenance agreement was executed with the turbine equipment supplier.

Walker Ridge Wind Project

The Walker Ridge Wind Project is a 144 MW wind power electric generating facility located in the counties of Lake and Colusa in northern California. The facility will be located on U.S. Bureau of Land Management land. A Large Generator Interconnection Agreement with CAISO and PG&E was executed in December 2018. Work is ongoing with respect to site design, environmental permitting and EPC engagement. Energy from the project is expected to be sold pursuant to a long term financial hedge. The expected COD date for the project is late 2020 or 2021.

Broad Mountain Wind Project

The Broad Mountain Wind Project is a 200 MW wind power electric generating facility located in Carbon County, Pennsylvania. Development of the project is planned to be completed in two phases. The first phase ("Phase I") representing installed capacity of 80 MW is targeted for completion, pending regulatory approvals, in 2020. The balance of the 120 MW of proposed capacity is targeted for completion in 2022. The project has secured the majority of land leases required, and environmental and interconnection studies are underway including geotechnical investigations, FAA permits and zoning applications for Phase I. Energy from Phase I of the project is expected to be sold pursuant to a long term financial hedge, and/or PPAs to local end users.

Shady Oaks II Wind Project

The Shady Oaks II Wind Project is a 120 MW expansion of the Liberty Power Group’s operational Shady Oaks Wind Facility, located in Lee County, Illinois. The project will be located on land adjacent to the existing facility, and, subject to interconnection studies that are currently in progress, will connect to the same point of interconnection. Work on environmental permitting and site design are ongoing. Energy from the expansion project is expected to be sold pursuant to a long term financial hedge. The expected COD date for the project is late 2020 or 2021.

Sandy Ridge II Wind Project

The Sandy Ridge II Wind Project is a 60 to 100 MW expansion of the Liberty Power Group’s operational Sandy Ridge Wind Facility, located in Centre County, Pennsylvania. The project will be located on land adjacent to the existing facility, and, subject to interconnection studies that are currently in progress, will connect to the same point of interconnection. Work on environmental permitting and site design is ongoing. Energy from the expansion project is expected to be sold pursuant to a long term financial hedge. The expected COD date for the project is late 2020 or early 2021.

Great Bay II Solar Project

The Great Bay II Solar Project is an approximately 45 MW expansion of the Liberty Power Group’s operational Great Bay Solar Facility, located in Somerset County in southern Maryland. The project will be located on land nearby the existing facility, and will connect to the same point of interconnection. Work on environmental permitting and site design is ongoing. Energy from the expansion project is expected to be sold pursuant to a long-term financial hedge. The expected COD date for the project is late 2019 or early 2020.

Wataynikaneyap Power Transmission Project

The Liberty Utilities Group acquired a 9.8% ownership interest in an electricity transmission project located in Northwestern Ontario (the "Wataynikaneyap Power Transmission Project") from Fortis Inc. that is expected to connect 17 remote First Nation communities to the Ontario provincial electricity grid through the construction of approximately 1,800 km of transmission lines. Ownership of the Wataynikaneyap Power Transmission Project is divided as follows: 9.8% held by the Liberty Utilities Group, 39.2% held by Fortis Inc. and 51% held equally among 24 First Nation partners.

The initial phase of the Wataynikaneyap Power Transmission Project connecting Pikangikum First Nation to Ontario's power grid was completed in late 2018. The next two phases are subject to receipt of all necessary regulatory approvals, including leave-to-construct approval from the Ontario Energy Board, which is expected in the first half of 2019. In addition to providing participating First Nations communities ownership in the transmission line, the Wataynikaneyap Power Transmission Project is expected to result in socio-economic benefits for surrounding communities, reduce environmental risk and lessen greenhouse gas emissions associated with diesel-fired generation currently used in the area.

International Development Activities

As a component of the acquisition of its interest in Atlantica, Algonquin secured an opportunity for AAGES to evaluate participation in a number of development opportunities which had been previously advanced by Abengoa. Since its formation in the first quarter of 2018, the AAGES development team has been actively evaluating its interest in international projects, including the following project:

ATN3 Electric Transmission Project

The ATN3 electric transmission project is an electric transmission development project located in southeast Peru consisting of a new 220 kV power transmission line approximately 320 km in length, a new 138 kV power transmission line approximately 7.2 km in length, two new substations and the expansion of three existing substations. The ATN3 Project will be operated under a concession agreement with the government of Peru, with an operating period of 30 years from the commencement of commercial operation and which grants to ATN3 an annual fixed tariff denominated in U.S. dollars and indexed to the U.S. consumer price index. Ownership of the project will be transferred to the government of Peru at the end of the 30 year concession term.

On November 8, 2018, AAGES entered into a definitive agreement with Abengoa Perú S.A. and Abengoa Greenfield Perú S.A. to acquire the entity that owns the project. Closing of the transaction remains subject to certain conditions, including receipt of certain approvals from the government of Peru.

SUMMARY OF PROPERTY, PLANT, AND EQUIPMENT EXPENDITURES[1]

(all dollar amounts in $ millions)	Three Months Ended December 31 2018	Three Months Ended December 31 2017	Twelve Months Ended December 31 2018	Twelve Months Ended December 31 2017
Liberty Utilities Group:				
Rate Base Maintenance	**$ 41.5**	$ 45.9	**$ 177.7**	$ 170.9
Rate Base Acquisition	**—**	—	**—**	2,058.2
Rate Base Growth	**76.0**	70.6	**173.9**	272.7
	$ 117.5	$ 116.5	**$ 351.6**	$ 2,501.8
Liberty Power Group:				
Maintenance	**$ 12.6**	$ 3.1	**$ 27.4**	$ 13.9
Investment in Capital Projects[1]	**(18.0)**	13.4	**71.6**	469.9
International Investments[2]	**345.0**	—	**957.6**	—
	$ 339.6	$ 16.5	**$ 1,056.6**	$ 483.8
Total Capital Expenditures	**$ 457.1**	$ 133.0	**$ 1,408.2**	$ 2,985.6

1 Includes expenditures on Property Plant & Equipment, equity-method investees, and acquisitions of operating entities that were jointly developed by the Company.

2 Investments in Atlantica are reflected at historical investment cost and not fair value.

2018 Fourth Quarter Property Plant and Equipment Expenditures

During the three months ended December 31, 2018, the Liberty Utilities Group invested $117.5 million in capital expenditures as compared to $116.5 million during the same period in 2017. The Liberty Utilities Group’s investment was primarily related to the construction of transmission and distribution main replacements, work on new and existing substation assets, and initiatives relating to the safety and reliability at the electric and gas systems.

During the three months ended December 31, 2018, the Liberty Power Group incurred capital expenditures of $339.6 million as compared to $16.5 million during the same period in 2017. The Liberty Power Group's investment was primarily related to the acquisition of an additional 16.5% interest in Atlantica, development costs for the Sugar Creek Wind Project, and ongoing maintenance capital at existing operating sites, partially offset by a repayment of a loan provided to the Amherst Island Wind Project.

2018 Annual Property Plant and Equipment Expenditures

During the twelve months ended December 31, 2018, the Liberty Utilities Group invested $351.6 million in capital expenditures as compared to $2.5 billion during the same period in 2017. Excluding the acquisition of Empire, the Liberty Utilities Group incurred capital expenditures of $443.6 million in 2017. The Liberty Utilities Group’s investment was primarily related to the construction of transmission and distribution main replacements, the completion and start of work on new and existing substation assets, and initiatives relating to the safety and reliability at the electric and gas systems. Capital expenditures in the same period last year (excluding the acquisition of Empire) included the completion of 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.

During the twelve months ended December 31, 2018, the Liberty Power Group incurred capital expenditures of $1,056.6 million as compared to $483.8 million during the same period in 2017. Excluding the 41.5% investment in Atlantica, the Liberty Power Group's investment was $99.0 million in 2018. The Liberty Power Group's investments primarily related to completion of the Great Bay Solar and Amherst Island Wind Facilities, early stages of environmental permitting for the Blue Hill Wind Project, the finalization of material construction contracts on the Val Eo Wind Project and ongoing maintenance capital at existing operating sites.

2019 Capital Investments

In 2019, the Company plans to spend between $1.4 billion and $1.6 billion on capital investment opportunities. Actual expenditures during the course of 2019 may vary due to timing of various project investments and the realized Canadian to U.S. dollar exchange rate.

Expected 2019 capital investment ranges are as follows:

(all dollar amounts in $ millions)			
Liberty Utilities Group:			
Rate Base Maintenance	$ 180.0	-	$ 200.0
Rate Base Growth	280.0	-	320.0
Utility Acquisitions	350.0	-	370.0
Total Liberty Utilities Group:	$ 810.0	-	$ 890.0
Liberty Power Group:			
Maintenance	$ 30.0	-	$ 40.0
Investment in Capital Projects	340.0	-	370.0
International Investments	220.0	-	300.0
Total Liberty Power Group:	$ 590.0	-	$ 710.0
Total 2019 Capital Investments	**$ 1,400.0**	**-**	**$ 1,600.0**

The Liberty Utilities Group intends to spend between $810.0 million - $890.0 million over the course of 2019 in an effort to expand our operations, improve the reliability of the utility systems and broaden the technologies used to better serve its service areas. Projects entail spending capital for structural improvements, specifically in relation to refurbishing substations, replacing poles and wires, drilling and equipping aquifers, main replacements, and reservoir pumping stations. Liberty expects to close the acquisitions of New Brunswick Gas, St. Lawrence Gas and the Turquoise Solar Project in 2019.

The Company expects to fund its 2019 capital plan through a combination of retained cash, tax equity funding, senior and subordinated debentures, bank revolving and term credit facilities, and common equity.

The Liberty Power Group intends to spend between $590.0 million - $710.0 million over the course of 2019 to develop or further invest in capital projects, primarily in relation to: (i) the purchase of the Amherst Island Wind Project from our Joint Venture Partner, (ii) development of the Sugar Creek Wind and Great Bay II Solar Projects, and (iii) additional international investments. 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.

LIQUIDITY AND CAPITAL RESERVES

APUC has revolving credit and letter of credit facilities available for Corporate, the Liberty Utilities Group, and the Liberty Power 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, 2018:

	As at December 31, 2018				As at Dec 31, 2017
(all dollar amounts in $ millions)	Corporate	Liberty Utilities	Liberty Power	Total	Total
Committed facilities	$ 121.0	$ 500.0	$ 700.0 [1]	**$ 1,321.0**	$ 1,101.4
Funds drawn on facilities/ Commercial paper issued	—	(103.0)	—	**(103.0)**	(54.3)
Letters of credit issued	(13.5)	(7.8)	(149.8)	**(171.1)**	(139.3)
Liquidity available under the facilities	**107.5**	**389.2**	**550.2**	**1,046.9**	907.8
Cash on hand				**46.8**	43.5
Total Liquidity and Capital Reserves	**$ 107.5**	**$ 389.2**	**$ 550.2**	**$ 1,093.7**	$ 951.3

[1] Includes a $200 million uncommitted stand alone letter of credit facility.

As at December 31, 2018, the Company's C$165.0 million senior unsecured revolving credit facility (the "Corporate Credit Facility") was undrawn and had $13.5 million of outstanding letters of credit. In November 2018, the facility's maturity was extended to November 19, 2019.

On December 21, 2017, the Company entered into a $600.0 million term credit facility with two Canadian banks ("Corporate Term Credit Facility"). The proceeds of the Corporate Term Credit Facility provide the Company with additional liquidity for general corporate purposes and acquisitions. On March 7, 2018 the Company drew $600.0 million under this facility and during the second and fourth quarter the Company repaid $132.5 million and $280.7 million respectively on the facility. In December 2018, the facility's maturity was extended to June 21, 2019. The Company plans to refinance the Corporate Credit Facility and the Corporate Term Credit Facility with a new revolving credit facility in the first half of 2019.

On February 23, 2018, the Liberty Utilities Group increased commitments on its senior unsecured syndicated revolving credit facility (the "Liberty Credit Facility") to $500.0 million and extended the maturity to February 23, 2023. In conjunction with the increase to the Liberty Credit Facility, the $200.0 million revolving credit facility at Empire 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 at December 31, 2018 the Liberty Credit Facility had drawn $97.0 million, backstopped $6.0 million in commercial paper issuances, and had $7.8 million in outstanding letters of credit.

As at December 31, 2018, the Liberty Power Group's bank lines consisted of a $500.0 million senior unsecured syndicated revolving credit facility (the "Liberty Power Credit Facility") maturing on October 6, 2023 and a $200.0 million letter of credit facility ("Liberty Power LC Facility") maturing January 31, 2021. As at December 31, 2018, the Liberty Power Credit Facility was undrawn and a total of $149.8 million of letters of credit were issued under this facility and the standalone Liberty Power LC Facility.

Long Term Debt

On June 1, 2018, the Company repaid, upon its maturity, a $90.0 million secured utility note.

On July 25, 2018, the Company repaid, upon its maturity, a C$135.0 million unsecured note.

<u>Issuance of Subordinated Notes</u>

On October 17, 2018, APUC issued $287.5 million of 6.875% fixed-to-floating subordinated notes. The issuance of the subordinated notes represented APUC's inaugural entry into the U.S. public debt markets. The subordinated notes are listed on the NYSE under the ticker symbol "AQNA".

The notes mature 60 years from issuance and are callable on or after year 5. For the initial 5 years, the notes carry a fixed interest rate of 6.875%. Subsequently, the interest rate will be set to equal the three-month London Interbank Offered Rate (LIBOR) plus a margin of 367.7 basis points from years 5 to 10, a margin of 392.7 basis points from years 10 to 25 and a margin of 467.7 basis points from years 25 to 60. The notes were initially assigned a rating of BB+/BB+ from S&P and Fitch. The notes were treated by both rating agencies as hybrid capital, receiving up to 50% equity credit for the balance outstanding.

The notes contain a 102% of par call feature in the event of a rating methodology change by either agency that would reduce the amount of the equity credit.

APUC believes the use of subordinated notes structured as hybrid capital is a cost effective financing method that can be used to obtain balance sheet equity credit. APUC plans to continue to expand this portion of its capital structure as a means to diversify its financing sources.

Issuance of Green Bonds

Subsequent to year-end on January 29, 2019, the Liberty Power Group issued C$300.0 million of senior unsecured debentures bearing interest at 4.60% and with a maturity date of January 29, 2029. The debentures were sold at a price of $999.52 per $1000.00 principal amount. The debentures represent Liberty Power Group's inaugural "green bond" offering, and are closely aligned with the Company's commitment to advancing a sustainable energy and water future. Under its recently implemented Green Bond Framework, the proceeds of any "green bond" offering are to be used to finance and/or refinance investments in renewable power generation and clean energy technologies.

As at December 31, 2018, the weighted average tenor of APUC's total long term debt is approximately 17 years with an average interest rate of 4.8%.

Credit Ratings

APUC has a long term consolidated corporate credit rating of BBB from Standard & Poor's ("S&P"), a BBB rating from DBRS and a BBB issuer rating from Fitch.

LUCo, parent company for the Liberty Utilities Group, has a corporate credit rating of BBB from S&P and a BBB issuer rating from Fitch. Debt issued by Liberty Finance, a special purpose financing entity of LUCo, has a rating of BBB (high) from DBRS and BBB+ from Fitch. Empire has an issuer rating of BBB from S&P and a Baa1 rating from Moody's Investors Service, Inc. ("Moody's").

APCo, the parent company for the Liberty Power Group, has a BBB issuer rating from S&P, a BBB issuer rating from DBRS and a BBB issuer rating from Fitch.

Contractual Obligations

Information concerning contractual obligations as of December 31, 2018 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]	**$ 3,321.8**	$ 334.9	$ 420.8	$ 825.6	$ 1,740.5
Convertible debentures	**0.5**	—	—	—	0.5
Advances in aid of construction	**63.7**	1.2	—	—	62.5
Interest on long-term debt obligations[2]	**1,576.9**	156.8	269.9	221.5	928.7
Purchase obligations	**325.3**	325.3	—	—	—
Environmental obligations	**59.2**	4.2	30.1	2.9	22.0
Derivative financial instruments:					
Cross currency swap	**93.2**	5.3	46.0	34.4	7.5
Interest rate swap	**8.5**	8.5	—	—	—
Energy derivative and commodity contracts	**1.2**	0.6	0.5	0.1	—
Purchased power	**282.6**	46.5	22.0	22.9	191.2
Gas delivery, service and supply agreements	**251.8**	77.7	79.0	46.8	48.3
Service agreements	**512.0**	43.7	77.5	78.2	312.6
Capital projects	**76.8**	67.6	1.9	7.3	—
Operating leases	**214.4**	7.6	14.3	13.9	178.6
Other obligations	**155.8**	33.4	—	—	122.4
Total Obligations	**$ 6,943.7**	**$ 1,113.3**	**$ 962.0**	**$ 1,253.6**	**$ 3,614.8**

1 Exclusive of deferred financing costs, bond premium/discount, fair value adjustments at the time of issuance or acquisition.

2 The subordinated notes have a maturity in 2078, however management intent is to repay in 2023 upon exercising its redemption right.

Equity

The common shares of APUC are publicly traded on the Toronto Stock Exchange ("TSX") and the New York Stock Exchange ("NYSE") under the trading symbol "AQN". As at December 31, 2018, APUC had 488,851,433 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 April 24, 2018, APUC closed the sale of approximately 37.5 million of its common shares to certain institutional investors at a price of C$11.85 per share, for gross proceeds of approximately C$444.4 million. The proceeds of the offering were used to pay down existing indebtedness and in part, to finance the purchase of the additional 16.5% interest in Atlantica.

On December 20, 2018, APUC closed the sale of approximately 12.5 million of its common shares to certain institutional investors at a price of C$13.76 per share, for gross proceeds of approximately C$172.5 million. The proceeds of the offering are anticipated to be used to partially finance APUC's recently announced acquisition of New Brunswick Gas, 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, 2018, APUC had outstanding:

- 4,800,000 cumulative rate reset Series A preferred shares, yielding 5.162% annually for the five-year period ending on December 31, 2023;
- 100 Series C preferred shares that were issued in exchange for 100 Class B limited partnership units by St. Leon Wind Energy LP; and
- 4,000,000 cumulative rate reset Series D preferred shares, yielding 5.0% 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, 2018, 123,522,018 common shares representing approximately 25% of total common shares outstanding had been registered with the Reinvestment Plan. During the year ended December 31, 2018, 5,880,843 common shares were issued under the Reinvestment Plan, and subsequent to year-end, on January 17, 2019, an additional 1,606,001 common shares were issued under the Reinvestment Plan.

SHARE-BASED COMPENSATION PLANS

For the twelve months ended December 31, 2018, APUC recorded $9.5 million in total share-based compensation expense as compared to $8.4 million for the same period in 2017. 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, 2018, total unrecognized compensation costs related to non-vested options and share unit awards were $1.2 million and $8.2 million, respectively, and are expected to be recognized over a period of 1.64 and 1.60 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, 2018, the Company granted 1,166,717 options to executives of the Company. The options allow for the purchase of common shares at a weighted average price of C$12.80, the market price of the underlying common share at the date of grant. During the year, executives of the Company exercised 1,493,694 stock options at a weighted average exercise price of C$10.66 in exchange for common shares issued from treasury and 95,517 options were settled at their cash value as payment for tax withholdings related to the exercise of the options.

As at December 31, 2018, a total of 6,292,642 options are issued and outstanding under the stock option plan.

Performance Share Units

APUC issues performance share units ("PSUs") and restricted share units ("RSUs") to certain members of management as part of APUC's long-term incentive program. During the twelve months ended December 31, 2018, the Company granted (including dividends and performance adjustments) 791,524 PSUs and RSUs to executives and employees of the Company. During the year, the Company settled 285,551 PSUs, of which 142,473 PSUs were exchanged for common shares issued from treasury and 143,078 PSUs were settled at their cash value as payment for tax withholdings related to the settlement of the PSUs. Additionally, during 2018, a total of 68,869 PSUs were forfeited.

As at December 31, 2018, a total of 1,392,132 PSUs and RSUs are granted and outstanding under the PSU and RSU plan.

Directors Deferred Share Units

APUC has a Directors' Deferred Share Unit Plan. Under the plan, non-employee directors of APUC receive all or any portion of their annual compensation in deferred share units ("DSUs") and may elect to receive any portion of their remaining compensation in DSUs. The DSUs provide for settlement in cash or shares at the election of APUC. As APUC does not expect to settle the DSUs in cash, these DSUs are accounted for as equity awards. During the twelve months ended December 31, 2018, the Company issued 86,750 DSUs (including DSUs in lieu of dividends) to the directors of the Company.

As at December 31, 2018, a total of 380,656 DSUs had been granted under the DSU plan.

Bonus Deferral Restricted Share Units

During the year, the Company introduced a new bonus deferral restricted share units ("RSUs") program to certain employees. The eligible employees have the option to receive a portion or all of their annual bonus payment in RSUs in lieu of cash. The RSUs provide for settlement in shares, and therefore these options are accounted for as equity awards. During the twelve months ended December 31, 2018, 131,611 RSUs were issued (including RSUs in lieu of dividends) to employees of the Company. During the year, the Company settled 4,545 RSUs in exchange for 2,111 common shares issued from treasury, and 2,434 RSUs were settled at their cash value as payment for tax withholdings related to the settlement of the RSUs.

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, 2018, the Company issued 252,698 common shares to employees under the ESPP.

As at December 31, 2018, a total of 1,032,251 shares had been issued under the ESPP.

MANAGEMENT OF CAPITAL STRUCTURE

APUC views its capital structure in terms of its debt and equity levels at its individual operating groups and at an overall company level.

APUC's objectives when managing capital are:

- To maintain its capital structure consistent with investment grade credit metrics appropriate to the sectors in which APUC operates;
- To maintain appropriate debt and equity levels in conjunction with standard industry practices and to limit financial constraints on the use of capital;
- To ensure capital is available to finance capital expenditures sufficient to maintain existing assets;
- To ensure generation of cash is sufficient to fund sustainable dividends to shareholders as well as meet current tax and internal capital requirements;
- To maintain sufficient liquidity to ensure sustainable dividends made to shareholders; and
- To have appropriately sized revolving credit facilities available for ongoing investment in growth and development opportunities.

APUC monitors its cash position on a regular basis to ensure funds are available to meet current normal as well as capital and other expenditures. In addition, APUC continuously reviews its capital structure to ensure its individual business groups are using a capital structure which is appropriate for their respective industries.

RELATED PARTY TRANSACTIONS

Equity-method investments

The Company entered in a number of transactions with equity-method investees in 2018 and 2017 (see *Note 8* in the annual audited consolidated financial statements).

The Company provides administrative and development services to its equity-method investees and is reimbursed for incurred costs. To that effect, the Company charged its equity-method investees $11.4 million in 2018 as compared to $4.7 million during the same period in 2017 (see *Note 8(d)* and *8(e)* in the annual audited consolidated financial statements).

Subject to certain limitations, Atlantica has a right of first offer on any proposed sale, transfer or other disposition by AAGES (other than to APUC) of its interest in infrastructure facilities that are developed or constructed in whole or in part by AAGES under long-term revenue agreements. Similarly, Atlantica has rights, subject to certain limitations, with respect to any proposed sale, transfer or other disposition of APUC's interest, not held through AAGES, in infrastructure facilities that are developed or constructed in whole or in part by APUC outside of Canada or the United States under long-term revenue agreements. There were no such transactions in 2018 (see *Note 8(a)* and *8(b)* in the annual audited consolidated financial statements).

Redeemable non-controlling interests

In 2018, contributions of $305.0 million were received from AAGES for preference shares of a wholly consolidated subsidiary of the Company (see *Note 8(a)* and *Note 17* in the annual audited consolidated financial statements).

Long Sault Hydro Facility

Effective December 31, 2013, APUC acquired the shares of Algonquin Power Corporation Inc. ("APC") which was partially owned by Senior Executives. APC owns the partnership interest in the 18 MW Long Sault Hydro Facility. A final post-closing adjustment related to the transaction remains outstanding.

The above related party transactions have been recorded at the exchange amounts agreed to by the parties to the transactions.

ENTERPRISE RISK MANAGEMENT

The Corporation is subject to a number of risks and uncertainties, certain of which are described below. A risk is the possibility that an event might happen in the future that could have a negative effect on the financial condition, financial performance or business of the Corporation. The actual effect of any event on the Corporation's business could be materially different from what is anticipated or described below. The description of risks below does not include all possible risks.

Led by the Chief Compliance and Risk Officer, the Corporation has an established enterprise risk management, or ("ERM"), framework. The Corporation's ERM framework follows the guidance of ISO 31000:2009 and the COSO Enterprise Risk Management - Integrated Framework. The Corporation's ERM framework is intended to systematically identify, assess and mitigate the key strategic, operational, financial and compliance risks that may impact the achievement of the Corporation's current objectives, as well as those inherent to strategic alternatives available to the Corporation. The Corporation's Board-approved ERM policy details the Corporation's risk management processes, risk appetite and risk governance structure.

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

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

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 from S&P, a BBB rating from DBRS and a BBB issuer rating from Fitch. APCo, the primary operating company of the Liberty Power Group, has a BBB issuer rating from S&P, BBB issuer rating from DBRS and a BBB issuer rating from Fitch. LUCo, parent company for the Liberty Utilities Group, has a corporate credit rating of BBB from S&P and a BBB issuer rating from Fitch. Debt issued by Liberty Finance, a special purpose financing entity of LUCo, has a rating of BBB (high) from DBRS and BBB+ from Fitch. Empire has a BBB issuer rating from S&P and a Baa1 issuer rating from Moody's.

The ratings indicate the agencies' assessment of the ability to pay the interest and principal of debt securities issued by such entities. A rating is not a recommendation to purchase, sell or hold securities and each rating should be evaluated independently of any other rating. The lower the rating, the higher the interest cost of the securities when they are sold. A downgrade in APUC's or its subsidiaries' issuer corporate credit ratings would result in an increase in APUC's borrowing costs under its bank credit facilities and future long-term debt securities issued. Any such downgrade could also adversely impact the market price of the outstanding securities of the Company. If any of APUC's ratings fall below investment grade (investment grade is defined as BBB- or above for S&P and Fitch, BBB (low) or above for DBRS and Baa3 or above for Moody's), APUC's ability to issue short-term debt or other securities or to market those securities would be 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 at December 31, 2018, the Company had approximately $3,337.3 million of long-term consolidated indebtedness. Management of the Company believes, based on its current expectations as to the Company's future performance, that the cash flow from its operations and funds available to it under its revolving credit facilities and its ability to access capital markets will be adequate to enable the Company to finance its operations, execute its business strategy and maintain an adequate level of liquidity. However, expected revenue and capital expenditures are only estimates. Moreover, actual cash flows from operations are dependent on regulatory, market and other conditions that are beyond the control of the Company. As such, no assurance can be given that management's expectations as to future performance will be realized.

The ability of the Company to raise additional debt or equity or to do so on favourable terms may be adversely affected by adverse financial and operational performance, or by financial market disruptions or other factors outside the control of the Company.

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

The Company will need to refinance or reimburse amounts outstanding under the Company's existing consolidated indebtedness over time. There can be no assurance that any indebtedness of the Company will be refinanced or that additional financing on commercially reasonable terms will be obtained, if at all. In the event that such indebtedness cannot be refinanced, or if it can be refinanced on terms that are less favourable than the current terms, the Company's cashflows and the ability of the Company to declare dividends may be adversely affected.

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

Interest Rate Risk

The majority of debt outstanding in APUC and its subsidiaries is subject to a fixed rate of interest and as such is not subject to significant interest rate risk in the short to medium term time horizon.

Borrowings subject to variable interest rates can vary significantly from month to month, quarter to quarter and year to year. APUC does not actively manage interest rate risk on its variable interest rate borrowings due to the primarily short term and revolving nature of the amounts drawn.

Based on amounts outstanding as at December 31, 2018, 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, 2018. As a result, a 100 basis point change in the variable rate charged would not impact interest expense;
- The Liberty Utilities Group's revolving credit facility is subject to a variable interest rate and had $97.0 million outstanding as at December 31, 2018. As a result, a 100 basis point change in the variable rate charged would impact interest expense by $1.0 million annually;
- The Liberty Utilities Group's commercial paper program is subject to a variable interest rate and had $6.0 million outstanding as at December 31, 2018. As a result, a 100 basis point change in the variable rate charged would impact interest expense by $0.1 million annually;
- The Liberty Power Group's revolving credit facility is subject to a variable interest rate and had no amounts outstanding as at December 31, 2018. As a result, a 100 basis point change in the variable rate charged would not impact interest expense; and
- The corporate term facilities are subject to a variable interest rate and had $321.8 million outstanding as at December 31, 2018. As a result, a 100 basis point change in the variable rate charged would impact interest expense by $3.2 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 10-year forward starting swap to fix the underlying interest rate for the anticipated refinancing of its C$135.0 million bond which matured in July 2018. On July 24, 2018, the Company amended and extended the forward-starting date of the interest rate swap to begin on March 29, 2019. Subsequent to year-end and concurrent with the issuance of C$300.0 million of senior unsecured debentures on January 29, 2019 this swap was unwound and settled.

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.

U.S. Tax Reform

On December 22, 2017, H.R. 1, the Tax Cuts and Jobs Act was signed into law which resulted in significant changes to U.S. tax law that will affect the Company (See *U.S. Tax Reform*). The U.S. Department of Treasury has released proposed regulations related to business interest expense limitations, Base Erosion Anti-Abuse Tax ("BEAT"), and anti-hybrid structures as part of the implementation of U.S. Tax Reform. These proposed regulations are not final and are subject to change in the regulatory review process which is expected to be completed later in 2019. The timing or impacts of any future changes in tax laws, including the impacts of proposed regulations, cannot be predicted. As a result, there may be future impacts on the results of operations, financial condition and cash flows of the Company beyond those described herein.

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.

The following chart sets out the Company's 10 largest customers and their credit ratings:

Counterparty	Credit Rating [1]	Approximate Annual Revenues	Percentage of APUC Revenue
PJM Interconnection LLC	Aa2	$ 25.5	1.5%
Manitoba Hydro	A+	21.0	1.3%
Hydro Quebec	AA-	21.4	1.3%
Commonwealth Edison	BBB	19.4	1.2%
Xcel Energy	A3	17.2	1.0%
Pacific Gas and Electric Company	D	22.0	1.3%
Wolverine Power Supply	A	24.2	1.5%
Independent Electricity System Operator of Ontario	A+	16.3	1.0%
Electric Reliability Council of Texas (ERCOT)	Aa3	11.9	0.7%
Connecticut Light and Power	A3	23.1	1.4%
Total		**$ 202.0**	

[1] Ratings by DBRS, Moody's, or S&P.

Liberty Power Group's revenues are approximately 14% of total Company revenues. Approximately 84% 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 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 $21.5 million which is spread over approximately 164,000 connections, resulting in an average outstanding balance of approximately $130 dollars per connection.

The natural gas distribution systems accounts receivable balances related to the natural gas utilities total $35.1 million, while electric distribution systems accounts receivable balances related to the electric utilities total $150.2 million. The natural gas and electrical utilities both derive over 85% of their revenue from residential customers and have a per connection average outstanding balance of $104 dollars and $565 dollars respectively

Adverse conditions in the energy industry or in the general economy, as well as circumstances of individual customers or counterparties, may adversely affect the ability of a customer or counterparty to perform as required under its contract with the Company. Losses from a utility customer may not be offset by bad debt reserves approved by the applicable utility regulator. If a customer under a long-term 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 for its operating facilities 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 $10 per MW-hr change in the market price would result in a change in revenue of approximately $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.

A third hedge for the Sandy Ridge Wind Facility will commence on January 1, 2024, for a five year period. The financial hedge commitment is declining over the five year period and is structured to hedge 74% of the Sandy Ridge Wind Facility’s expected production volume against exposure to PJM Western Hub current spot market rates in 2024, stepping down to 19% by 2028. The annual unhedged production based on long term projected averages is approximately 41,000 MW-hrs in 2024, stepping up to 128,000 MW-hrs by 2028.

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 $10 per MW-hr change in the market price would result in a change in revenue of approximately $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 $10 per MW-hr change in market prices would result in a change in revenue of approximately $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.

A third hedge for the Minonk Wind Facility will commence on January 1, 2024, for a one year period. The financial hedge is structured to hedge 37% 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 423,000 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, 2018, the Liberty Power Group had entered into hedges with a cumulative notional quantity of 7,440 MW-hrs.

The January 1, 2013 acquisition of the Shady Oaks Wind Facility included a power sales contract, which commenced on June 1, 2012 for a 20 year period. The power sales contract is structured to hedge the preponderance of the Shady Oaks Wind Facility's production volume against exposure to PJM ComEd Hub current spot market rates. For the unhedged portion of production based on expected long term average production, each $10 per MW-hr change in market prices would result in a change in revenue of approximately $0.5 million for the year.

The Company has elected the fair value option under ASC 825, *Financial Instruments* to account for its investment in Atlantica, with changes in fair value reflected in the annual audited consolidated statement of operations. As a result, each dollar change in the traded price of Atlantica shares will correspondingly affect the Company's Net Earnings by approximately $41.6 million.

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 $0.1 million on an annual basis.
- The Windsor Locks Thermal Facility's Energy Services Agreement includes provisions which reduce its exposure to natural gas price risk but has exposure to market rate conditions for sales above those to its primary customer. In this regard, a $1.00 increase in the price of natural gas per MMBTU, based on expected production levels, would result in a decrease in net revenue by approximately $0.5 million on an annual basis.
- The Maritime region provides short-term energy requirements to various customers at fixed rates. The energy requirements of these customers are estimated at approximately 190,000 MW-hrs in fiscal 2019, of which 181,000 MW-hrs is presently contracted. While the Tinker Hydro Facility is expected to provide the majority of the energy required to service these customers, the Maritime region anticipates having to purchase approximately 41,000 MW-hrs of its energy requirements at the ISO-NE spot rates to supplement self-generated energy should the Maritime region not be able to reach the estimated 190,000 MW-hrs. The risk associated with the expected market purchases of 41,000 MW-hrs is mitigated through the use of short-term financial energy hedge contracts which cover approximately 27% of the Maritime region's anticipated purchases during the price-volatile winter months at an average rate of approximately $77 per MW-hr. For the amount of anticipated purchases not covered by hedge contracts, each $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 California Public Utilities Commission ("CPUC"). The Calpeco Electric System purchases the energy, capacity, and related service requirements for its customers from NV Energy via a PPA at rates reflecting NV Energy's system average costs.

The Calpeco Electric System's tariffs allow for the pass-through of energy costs to its rate payers on a dollar for dollar basis, through the ECAC mechanism, which allows for the recovery or refund of changes in energy costs that are caused by the fluctuations in the price of fuel and purchased power. On a monthly basis, energy costs are compared to the CPUC approved base tariff energy rates and the difference is deferred to a balancing account. Annually, based on the balance of the ECAC balancing account, if the ECAC revenues were to increase or decrease by more than 5%, the Calpeco Electric System's ECAC tariff allows for a potential adjustment to the ECAC rates which would eliminate the risk associated with the fluctuating cost of fuel and purchased power.

The Granite State Electric System is an open access electric utility allowing for its customers to procure commodity services from competitive energy suppliers. For those customers that do not choose their own competitive energy supplier, Granite State Electric System provides a Default Service offering to each class of customers through a competitive bidding process. This process is undertaken semi-annually for all 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 18% of its normal winter period purchases under a NHPUC approved hedging program. All costs associated with the fixed basis hedging program are allowed to be a pass-through to customers through the COG filing and the approved rates in said filing. Should commodity prices increase or decrease relative to the initial semi-annual COG rate filing, the EnergyNorth Natural Gas System has the right to automatically adjust its rates going forward in order to minimize any under or over collection of its gas costs. In addition, any under collections may be carried forward with interest to the next year's corresponding COG filing, i.e. winter to winter and summer to summer.

The Midstates Gas Systems purchases pipeline capacity, storage and commodity from a variety of counterparties, and files with the three individual state commissions for recovery of its transportation and commodity costs through an annual Purchase Gas Adjustment ("PGA") filing and approval process. The Midstates Gas Systems establishes rates for its customers within the PGA filing and these rates are designed to fully recover its anticipated transportation and commodity costs. In order to minimize commodity price fluctuations, the Company has implemented a commodity hedging program designed to hedge approximately 25-50% of its non-storage related commodity purchases. All gains and losses associated with the hedging program are allowed to be a pass-through to customers through the PGA filing and are embedded in the approved rates in said filing. Rates can be adjusted on a monthly or quarterly basis in order to account for any commodity price increase or decrease relative to the initial PGA rate, minimizing any under or over collection of its gas costs. Similar to the Midstates Gas Systems, the Empire Gas System serves customers in Missouri, and also implements a commodity hedging program designed to hedge 70 to 90% of its winter demand inclusive of storage volumes withdrawn during the winter period. All related costs are embedded in approved rates and are passed-through to customers in the PGA. The Empire Gas System is permitted to file an Actual Cost Adjustment ("ACA") once a year which also includes a PGA filing. In addition to the ACA filing, three more optional PGA filings are allowed during the year. The gas segment's ACA year is from September 1 to August 31 for each year.

The Georgia (Peach State) Gas System purchases pipeline capacity, storage and commodity from a variety of counterparties, and files with the Georgia Public Service Commission ("PSC") for recovery of its transportation, storage and commodity costs through a monthly PGA filing process. The Peach State Gas System establishes rates for its customers within the PGA filings and these rates are designed to fully recover its anticipated transportation, storage and commodity costs. In order to minimize commodity price fluctuations, the annual Gas Supply Plan filed by the Company and approved by the Georgia PSC includes a commodity hedging program designed to hedge approximately 30% of its non-storage related commodity purchases during the winter months. All gains and losses associated with the hedging program are passed through to customers in the PGA filings and are embedded in the approved rates in such filings. Rates can be adjusted on a monthly basis in order to account for any differences in gas costs relative to the amounts assumed in the PGA filings, minimizing any under or over collection of its gas costs.

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 41% of its 2018 generation fuel supply need through coal. Approximately 98% of its 2018 coal supply was Western coal. Empire has contracts and binding proposals to supply a portion of the fuel for its coal plants through 2019. These contracts and inventory on hand satisfy approximately 50% of anticipated fuel requirements for 2019 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 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.

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.

These risks are mitigated through the diversification of APUC's operations, both operationally and geographically, the use of regular maintenance programs, including pipeline safety programs and compliance programs, and maintaining adequate insurance, an active Enterprise Risk Management program and the establishment of reserves for expenses.

Regulatory Risk

Profitability of APUC businesses is, in part, dependent on regulatory climates in the jurisdictions in which those businesses operate. In the case of some of 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 has had a significant impact on regulatory revenue requirements of most public utilities, including the Liberty Utilities Group. Throughout the course of 2018, the Liberty Utilities Group obtained orders from the majority of its principal regulators covering approximately 93% of customers, resulting in the reduction of customer rates in connection with the reduction in tax rates. Collectively, the orders represent an annualized aggregate reduction in utility revenues of approximately $35 million, of which approximately $18 million has been realized in 2018. Since the Company has not yet received rate orders addressing U.S. Tax Reform for all of its utilities, the full impact of rate reductions related to U.S. Tax Reform is not known.

Condemnation Expropriation Proceedings

The 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.

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 ("Liberty Apple Valley"). The lawsuit will be adjudicated in phases. In the first phase, the Court will determine whether to allow the taking by the Town; under California law, the taking will be allowed unless Liberty Apple Valley proves there is not a “public necessity” for the taking. If Liberty Apple Valley prevails, the case is concluded and the Town will be required to compensate Liberty Apple Valley for its litigation expenses. However, if the Court determines that the taking is allowed, there will be a second phase of the trial in which a jury will determine the amount of compensation owed for the taking based upon the fair market value of the assets being condemned. The 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 denying Liberty Apple Valley’s CEQA claim. As a result, the condemnation case will proceed. At present, discovery related to the first phase of the trial is ongoing. The trial date has been set for September 30, 2019 and is expected to last approximately four weeks. If, following that trial, there is a need for a second phase to determine compensation, that trial can be expected to occur six to twelve months after the conclusion of the first phase.

Acquisition Risk

Part of the Company's business strategy is to acquire new generating stations and existing regulated utilities. The Company's acquisition strategy introduces exposures inherent to such transactions that may adversely affect the results of an acquisition, including 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.

International Investment Risk

The Company’s investment in Atlantica exposes the Company to certain risks that are particular to Atlantica’s business and the markets in which Atlantica operates.

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

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

Joint Venture Investment Risk

The Company has, and will in the future continue to have, an equity interest of 50% or less in certain projects. As a result, the Company will not control such projects and may be subject to the decision-making of third parties, whose interests may not always be aligned with those of the Company. This may limit the Company's flexibility and financial returns with respect to these projects.

The Company has, and will in the future continue to have, an interest in projects over which it does not have sole control. 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 Company's economic or business interests or goals;
- may take actions contrary to the Company's policies or objectives with respect to the Company'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 Company;
- 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 Company that might affect the Company's ability to develop a project; or
- may have competing interests in the Company's markets that could create conflict of interest issues.

Further, the Company will not have sole control of certain major decisions relating to the projects that the Company owns or pursues through AAGES, including, among others, decisions relating to funding and transactions with affiliates. The Company's involvement with AAGES may also present a reputational risk, including from the reputation of Abengoa.

AAGES has obtained a 3 year secured credit facility in the amount of $306.5 million ("AAGES Credit Facility"), which is collateralized through a pledge of the Atlantica shares. A collateral shortfall would occur if the net obligation as defined in the agreement would equal or exceed 50% of the market value of the Atlantica shares. In the event of a collateral shortfall AAGES is required to post additional collateral in cash to reduce the net obligation to 40% of the total collateral provided ("Collateral Reset Level"). If AAGES were unable to fund the collateral shortfall, the AAGES Credit Facility lenders hold the right to sell Atlantica stock to reduce the facility to the Collateral Reset Level. The AAGES Credit Facility is repayable on demand if Atlantica ceases to be a public company. If AAGES were unable to repay the amounts owed, the lenders would have the right realize on their collateral (see *Note 8(a)* in the annual audited consolidated financial statements).

Asset Retirement Obligations

APUC and its subsidiaries complete periodic reviews of potential asset retirement obligations that may require recognition. As part of this process, APUC and its subsidiaries consider the contractual requirements outlined in their operating permits, leases, and other agreements, the probability of the agreements being extended, the ability to quantify such expense, the timing of incurring the potential expenses, as well as other factors which may be considered in evaluating if such obligations exist and in estimating the fair value of such obligations.

In conjunction with acquisitions and developed projects, the Company assumed certain asset retirement obligations. The asset retirement obligations mainly relate to legal requirements for: (i) removal or decommissioning of power generating facilities; (ii) cut (disconnect from the distribution system), purge (clean of natural gas and PCB contaminants), and cap gas mains within the gas distribution and transmission system when mains are retired in place, or dispose of sections of gas mains when removed from the pipeline system; (iii) clean and remove storage tanks containing waste oil and other waste contaminants; and (iv) remove asbestos upon major renovation or demolition of structures and facilities.

Cycles and Seasonality

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 review 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 6 of 12 states. An example of such a mechanism is seen at the Peach State Gas System in Georgia, where a weather normalization adjustment is applied to customer bills during the months of October through May that adjusts commodity rates to stabilize the revenues of the utility for changes in billing units attributable to weather patterns.

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.

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 litigation, claims and other legal and regulatory proceedings that arise from time to time in the ordinary course of business. Any accruals for contingencies related to these items are recorded in the financial statements at the time it is concluded that a material financial loss is likely and the related liability is estimable.

Anticipated recoveries under existing insurance policies are recorded when reasonably assured of recovery.

Claim by Gaia Power Inc.

On October 30, 2018, Gaia Power Inc. ("Gaia") commenced an action in the Ontario Superior Court of Justice against APUC and certain of its subsidiaries, claiming damages of not less than $345 million and punitive damages in the sum of $25 million. The action arises from Gaia's 2010 sale, to a subsidiary of APUC, of Gaia's interest in certain proposed wind farm projects in Canada. Pursuant to a 2010 royalty agreement, Gaia is entitled to royalty payments if the projects are developed and achieve certain agreed targets.

APUC believes that the claims are without merit, and intends to vigorously defend the action.

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 and device theft. Should a material breach occur the Company may not be able to recover all costs and losses through insurance, legal or regulatory processes.

Energy Consumption and Advancement in Technologies Risk

The 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 in accordance with the industry practice. 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, 2018:

(all dollar amounts in $ millions except per share information)	1st Quarter 2018	2nd Quarter 2018	3rd Quarter 2018	4th Quarter 2018
Revenue	$ 494.8	$ 366.2	$ 366.5	$ 419.9
Net earnings attributable to shareholders	17.6	65.5	57.9	44.0
Net earnings per share	0.04	0.14	0.12	0.09
Adjusted Net Earnings[1]	141.1	50.9	49.7	70.5
Adjusted Net Earnings per share[1]	0.30	0.11	0.10	0.14
Adjusted EBITDA[1]	279.2	160.3	166.9	196.9
Total assets	8,941.8	8,920.7	9,072.6	9,389.0
Long term debt[2]	3,832.7	3,448.1	3,561.3	3,337.3
Dividend declared per common share	$ 0.12	$ 0.13	$ 0.13	$ 0.13

	1st Quarter 2017	2nd Quarter 2017	3rd Quarter 2017	4th Quarter 2017
Revenue	$ 421.7	$ 337.0	$ 353.7	$ 409.5
Net earnings attributable to shareholders	19.3	35.3	47.7	47.2
Net earnings per share	0.05	0.09	0.12	0.11
Adjusted Net Earnings[1]	66.5	39.5	52.0	67.0
Adjusted Net Earnings per share[1]	0.19	0.09	0.13	0.16
Adjusted EBITDA[1]	192.3	147.1	164.2	185.8
Total assets	8,174.9	8,113.3	8,258.6	8,395.6
Long term debt[2]	3,586.5	3,404.5	3,553.7	3,080.5
Dividend declared per common share	$ 0.12	$ 0.12	$ 0.12	$ 0.12

1 See *Non-GAAP Financial Measures*

2 Includes current portion of long-term debt, long-term debt and convertible debentures.

The quarterly results are impacted by various factors including seasonal fluctuations and acquisitions of facilities as noted in this MD&A.

Quarterly revenues have fluctuated between $337 million and $494.8 million over the prior two year period. A number of factors impact quarterly results including acquisitions, seasonal fluctuations, and winter and summer rates built into the PPAs. In addition, a factor impacting revenues year over year is the fluctuation in the strength of the Canadian dollar relative to the U.S. dollar which can result in significant changes in reported revenue from Canadian operations.

Quarterly net earnings attributable to shareholders have fluctuated between $17.6 million and $65.5 million over the prior two year period. Earnings have been significantly impacted by non-cash factors such as deferred tax recovery and expense, impairment of intangibles, property, plant and equipment and mark-to-market gains and losses on financial instruments.

SUMMARY FINANCIAL INFORMATION OF ATLANTICA

The Company has a 41.5% interest in the common stock of Atlantica. APUC accounts for its interest in Atlantica using the fair value method (see *Note 8(a)* in the annual audited consolidated financial statements). The summary financial information of Atlantica in the following table is derived from the audited consolidated financial statements of Atlantica as of December 31, 2018 and 2017 and for the years then ended which are reported in U.S. dollars and were prepared using International Financial Reporting Standards, as issued by the International Accounting Standards Board ("IFRS"). The recognition, measurement and disclosure requirements of IFRS differ from U.S. GAAP as applied by the Company.

(all dollar amounts in $ millions)	2018	2017
Revenue	**$ 1,043.8**	$ 1,008.4
Profit (loss) for the year	**55.3**	(104.9)
Total non-current assets	**8,791.3**	9,350.4
Total current assets	**1,127.7**	1,141.9
Total non-current liabilities	**7,423.8**	8,096.5
Total current liabilities	**739.1**	500.4

DISCLOSURE CONTROLS AND PROCEDURES

APUC's management carried out an evaluation as of December 31, 2018, 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, 2018, 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.

Management assessed the effectiveness of the Company's internal control over financial reporting as of December 31, 2018, 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, 2018 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, 2018, 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.

INHERENT LIMITATIONS ON EFFECTIVENESS OF CONTROLS

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

CRITICAL ACCOUNTING ESTIMATES AND POLICIES

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

APUC's significant accounting policies and new accounting standards are discussed in *notes 1* and *2* 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.

Consolidation and Variable Interest Entities

The Company uses judgment to assess whether its operations or investments represent variable interest entities ("VIEs"). In making these evaluations, management considers a) the sufficiency of the investment's equity at risk, b) the existence of a controlling financial interest, and c) the structure of any voting rights. In addition, management considers the specific facts and circumstances of each investment in a VIE when determining whether the Company is the primary beneficiary. The factors that management takes into consideration include the purpose and design of the VIE, the key decisions that affect its economic performance, and whether the Company has the power to direct the activities that would most significantly affect the economic performance of the VIE. Management's judgment is also required to determine whether the Company has the right to receive benefits or the obligation to absorb losses of the VIE. Based on the judgments made, the Company will consolidate the VIE if it determines that it is the primary beneficiary.

Estimated Useful Lives and Recoverability of Long-Lived Assets, Intangibles and Goodwill

The Company makes judgments a) to determine the recoverability of a development project, and the period over which the costs are capitalized during the development and construction of the project, b) to assess the nature of the costs to be capitalized, c) to distinguish individual components and major overhauls, and d) to determine the useful lives or unit-of-production over which assets are depreciated.

Depreciation rates on utility assets are subject to regulatory review and approval, and depreciation expense is recovered through rates set by ratemaking authorities. The recovery of those costs is dependent on the ratemaking process.

The carrying value of long-lived assets, including intangible assets and goodwill, is reviewed whenever events or changes in circumstances indicate that such carrying values may not be recoverable, and at least annually for goodwill. Some of the factors APUC considers as indicators of impairment include a significant change in operational or financial performance, unexpected outcome from rate orders, natural disasters, energy pricing and changes in regulation. When such events or circumstances are present, the Company assesses whether the carrying value will be recovered through the expected future cash flows. If the facility includes goodwill, the fair value of the facility is compared to its carrying value. Both methodologies are sensitive to the forecasted cash flows and in particular energy prices, long-term growth rate and, discount rate for the fair value calculation.

In 2018 and 2017, 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 adopted the new standard using the modified retrospective method effective January 1, 2018. The adoption of Topic 606 did not have a material impact on the consolidated financial statements and the pattern of revenue recognition.

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-2018) recently released by the Society of Actuaries adjusted to reflect the 2018 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 adopted this guidance effective January 1, 2018.

Following the effective date of this Accounting Standards Update ("ASU"), the Company's regulated operations only capitalize the service costs component and therefore no regulatory to U.S. GAAP reporting differences exist. The Company has applied 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 2018 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.

	2018 Pension Plans		2018 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	(43.9)	(4.1)	(22.8)	(1.0)
1% decrease	53.6	3.9	29.0	2.5
Future compensation rate				
1% increase	0.3	0.6	—	—
1% decrease	(0.3)	(2.7)	—	—
Expected return on plan assets				
1% increase	—	(3.5)	—	(1.2)
1% decrease	—	3.5	—	1.4
Life expectancy				
10% increase	26.1	2.8	15.1	1.8
10% decrease	(27.7)	(4.0)	(14.5)	(1.4)
Health care trend				
1% increase	—	—	28.0	4.4
1% decrease	—	—	(22.2)	(2.6)

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, on EDGAR at www.sec.gov/edgar, and on the APUC website at www.AlgonquinPowerandUtilities.com.

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, 2018, 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, 2018.

February 28, 2019

/s/ Ian Robertson
Chief Executive Officer

/s/ David Bronicheski
Chief Financial Officer

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

Opinion on the Consolidated Financial Statements

We have audited the accompanying consolidated balance sheets of Algonquin Power & Utilities Corp. (the "Company") as of December 31, 2018 and December 31, 2017, the related consolidated statements of operations, comprehensive income, equity and cash flows for the years then ended, and the related notes (collectively referred to as the "consolidated financial statements"). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2018 and December 31, 2017, and the results of its operations and its cash flows for the years then ended in conformity 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, 2018, based on the criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework), and our report dated February 28, 2019 expressed an unqualified opinion thereon.

Basis for Opinion

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

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

/s/ Ernst & Young LLP

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

Toronto, Canada

February 28, 2019

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

Opinion on Internal Control over Financial Reporting

We have audited Algonquin Power & Utilities Corp.'s internal control over financial reporting as of December 31, 2018, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) (the "COSO criteria"). In our opinion, Algonquin Power & Utilities Corp. (the "Company") maintained, in all material respects, effective internal control over financial reporting as of December 31, 2018, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) ("PCAOB"), the consolidated balance sheets as at December 31, 2018 and December 31, 2017, and the consolidated statements of operations, comprehensive income, equity and cash flows for the years then ended, and the related notes, and our report dated February 28, 2019 expressed an unqualified opinion thereon.

Basis for Opinion

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

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

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

Definition and Limitations of Internal Control Over Financial Reporting

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

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

/s/ Ernst & Young LLP

Toronto, Canada

February 28, 2019

Algonquin Power & Utilities Corp.
Consolidated Balance Sheets

(thousands of U.S. dollars)

	December 31, 2018	December 31, 2017
ASSETS		
Current assets:		
Cash and cash equivalents	$ 46,819	$ 43,484
Accounts receivable, net (note 4)	245,728	244,617
Fuel and natural gas in storage	43,063	44,414
Supplies and consumables inventory	52,537	45,074
Regulatory assets (note 7)	59,037	66,567
Prepaid expenses	27,283	31,005
Derivative instruments (note 23)	9,616	16,099
Other assets and long-term investments (notes 8 and 11)	7,522	7,110
	491,605	498,370
Property, plant and equipment, net (note 5)	6,393,558	6,304,897
Intangible assets, net (note 6)	54,994	51,103
Goodwill (note 6)	954,282	954,282
Regulatory assets (note 7)	391,437	374,959
Derivative instruments (note 23)	53,192	54,115
Long-term investments (note 8)		
Investment carried at fair value	814,530	—
Notes receivable from equity investees	101,416	30,060
Other long-term investments	32,955	37,271
Deferred income taxes (note 18)	72,415	61,357
Other assets (note 11)	28,584	29,153
	$ 9,388,968	$ 8,395,567

Algonquin Power & Utilities Corp.
Consolidated Balance Sheets

(thousands of U.S. dollars)

	December 31, 2018	December 31, 2017
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable	$ 89,740	$ 119,887
Accrued liabilities	235,586	280,144
Dividends payable (note 15)	62,613	50,445
Regulatory liabilities (note 7)	39,005	37,687
Long-term debt (note 9)	13,048	12,364
Other long-term liabilities (note 12)	42,337	46,754
Derivative instruments (note 23)	14,339	14,126
Other liabilities	2,313	2,623
	498,981	564,030
Long-term debt (note 9)	3,323,747	3,067,187
Regulatory liabilities (note 7)	539,587	538,437
Deferred income taxes (note 18)	444,145	399,148
Derivative instruments (note 23)	88,503	54,818
Pension and other post-employment benefits obligation (note 10)	191,915	168,189
Other long-term liabilities (note 12)	263,582	242,105
	4,851,479	4,469,884
Redeemable non-controlling interests (note 17)		
Redeemable non-controlling interests, held by related party	307,622	—
Redeemable non-controlling interests	33,364	41,553
Equity:		
Preferred shares (note 13(b))	184,299	184,299
Common shares (note 13(a))	3,562,418	3,021,699
Additional paid-in capital	45,553	38,569
Deficit	(595,259)	(524,311)
Accumulated other comprehensive loss (note 14)	(19,385)	(2,792)
Total equity attributable to shareholders of Algonquin Power & Utilities Corp.	3,177,626	2,717,464
Non-controlling interests (note 17)	519,896	602,636
Total equity	3,697,522	3,320,100
Commitments and contingencies (note 21)		
Subsequent events (notes 8, 9, 13 and 23)		
	$ 9,388,968	$ 8,395,567

See accompanying notes to consolidated financial statements

Algonquin Power & Utilities Corp.
Consolidated Statements of Operations

(thousands of U.S. dollars, except per share amounts)	**Year ended December 31**	
	2018	**2017**
Revenue		
Regulated electricity distribution	$ 831,196	$ 763,501
Regulated gas distribution	430,377	376,806
Regulated water reclamation and distribution	128,437	140,082
Non-regulated energy sales	235,359	217,542
Other revenue	22,018	24,007
	1,647,387	1,521,938
Expenses		
Operating expenses	472,466	450,231
Regulated electricity purchased	265,166	222,443
Regulated gas purchased	183,012	141,689
Regulated water purchased	8,796	9,503
Non-regulated energy purchased	27,164	19,590
Administrative expenses	52,710	49,640
Depreciation and amortization	260,772	251,314
Loss (gain) on foreign exchange	(58)	323
	1,270,028	1,144,733
Operating income	377,359	377,205
Interest expense on long-term debt and others	152,118	142,439
Interest expense on convertible debentures and amortization of acquisition financing (notes 9(b) and 12(h))	—	13,383
Change in value of investment carried at fair value (note 8(a))	137,957	—
Interest, dividend, equity and other income (note 8)	(53,139)	(9,238)
Pension and post-employment non-service costs (note 10)	3,914	9,035
Other net losses	2,725	664
Acquisition-related costs, net (note 12(f))	687	47,708
Loss (gain) on derivative financial instruments (note 23(b)(iv))	636	(1,918)
	244,898	202,073
Earnings before income taxes	132,461	175,132
Income tax expense (note 18)		
Current	11,347	7,517
Deferred	42,025	65,910
	53,372	73,427
Net earnings	79,089	101,705
Net effect of non-controlling interests (note 17)		
Net effect of non-controlling interests	108,521	47,770
Net effect of non-controlling interests held by related party	(2,622)	—
Net earnings attributable to shareholders of Algonquin Power & Utilities Corp.	$ 184,988	$ 149,475
Series A and D Preferred shares dividend (note 15)	8,027	8,020
Net earnings attributable to common shareholders of Algonquin Power & Utilities Corp.	$ 176,961	$ 141,455
Basic and diluted net earnings per share (note 19)	$ 0.38	$ 0.37

See accompanying notes to consolidated financial statements

Algonquin Power & Utilities Corp.
Consolidated Statements of Comprehensive Income

(thousands of U.S. dollars)	**Year ended December 31**	
	2018	**2017**
Net earnings	$ 79,089	$ 101,705
Other comprehensive income (loss):		
Foreign currency translation adjustment, net of tax recovery of $4,532 and $169, respectively (notes 1(v), 23(b)(iii) and 23(b)(iv))	(27,969)	(21,753)
Change in fair value of cash flow hedges, net of tax recovery of $952 and expense of $599, respectively (note 23(b)(ii))	(2,690)	1,626
Change in value of available-for-sale investments	—	(65)
Change in pension and other post-employment benefits, net of tax expense of $696 and $512, respectively (note 10)	1,960	376
Other comprehensive loss, net of tax	(28,699)	(19,816)
Comprehensive income	50,390	81,889
Comprehensive loss attributable to the non-controlling interests	(107,380)	(47,743)
Comprehensive income attributable to shareholders of Algonquin Power & Utilities Corp.	$ 157,770	$ 129,632

See accompanying notes to consolidated financial statements

Algonquin Power & Utilities Corp.
Consolidated Statement of Equity

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

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

Algonquin Power & Utilities Corp.
Consolidated Statement of Equity

(thousands of U.S. dollars)
For the year ended December 31, 2017

	Algonquin Power & Utilities Corp. Shareholders						
	Common shares	Preferred shares	Additional paid-in capital	Accumulated deficit	Accumulated OCI	Non-controlling interests	Total
Balance, December 31, 2016	$ 1,674,591	$ 184,299	$ 34,892	$ (478,343)	$ 17,051	$ 418,826	$ 1,851,316
Net earnings (loss)	—	—	—	149,475	—	(47,770)	101,705
Redeemable non-controlling interests not included in equity (note 17)	—	—	—	—	—	10,358	10,358
Other comprehensive income (loss)	—	—	—	—	(19,843)	27	(19,816)
Dividends declared and distributions to non-controlling interests	—	—	—	(158,064)	—	(3,860)	(161,924)
Dividends and issuance of shares under dividend reinvestment plan (note 13(a)(ii))	35,873	—	—	(35,873)	—	—	—
Common shares issued pursuant to public offering, net of costs (note 13(a)(i))	440,024	—	—	—	—	—	440,024
Common shares issued upon conversion of convertible debentures (note 12(h))	855,691	—	—	—	—	—	855,691
Common shares issued pursuant to share-based awards (note 13(c))	15,520	—	(4,910)	(1,506)	—	—	9,104
Share-based compensation (note 13 (c))	—	—	8,587	—	—	—	8,587
Contributions received from non-controlling interests (notes 3(d), 3(g) and 8(f)(ii)), net of costs	—	—	—	—	—	225,055	225,055
Balance, December 31, 2017	$ 3,021,699	$ 184,299	$ 38,569	$ (524,311)	$ (2,792)	$ 602,636	$ 3,320,100

See accompanying notes to consolidated financial statements

Algonquin Power & Utilities Corp.
Consolidated Statements of Cash Flows

(thousands of U.S. dollars)	Year ended December 31	
	2018	**2017**
Cash provided by (used in):		
Operating Activities		
Net earnings from continuing operations	$ 79,089	$ 101,705
Adjustments and items not affecting cash:		
Depreciation and amortization	281,163	256,775
Deferred taxes	42,025	65,910
Unrealized (gain) loss on derivative financial instruments	(1,781)	1,466
Share-based compensation expense	7,495	8,292
Cost of equity funds used for construction purposes	(2,728)	(2,335)
Change in value of investments carried at fair value	137,957	—
Pension and post-employment contributions in excess of expense	(6,354)	(20,687)
Distributions received from equity investments, net of income	5,698	2,420
Others	(4,086)	740
Changes in non-cash operating items (note 22)	(8,126)	(87,719)
	530,352	326,567
Financing Activities		
Increase in long-term debt	2,015,533	1,386,743
Decrease in long-term debt	(1,699,592)	(2,366,105)
Issuance of convertible debentures, net of costs	—	571,944
Cash dividends on common shares	(166,384)	(127,530)
Dividends on preferred shares	(8,027)	(8,020)
Contributions from non-controlling interests, related party (note 17)	305,000	—
Contributions from non-controlling interests (note 17)	15,250	248,229
Production-based cash contributions from non-controlling interest	13,860	7,930
Distributions to non-controlling interests	(9,289)	(3,186)
Issuance of common shares, net of costs	473,911	438,810
Proceeds from settlement of derivative assets	—	36,676
Proceeds from exercise of share options	4,504	9,563
Shares surrendered to fund withholding taxes on exercised share options	(2,088)	(3,310)
Increase in other long-term liabilities	9,403	28,010
Decrease in other long-term liabilities	(20,144)	(6,709)
	931,937	213,045
Investing Activities		
Acquisitions of operating entities	—	(1,519,923)
Divestiture of operating entity	—	83,863
Additions to property, plant and equipment	(466,369)	(565,103)
Increase in other assets	(5,912)	(7,239)
Receipt of principal on notes receivable	17,950	—
Increase in long-term investments	(1,005,072)	(63,656)
Decrease in long-term investments	1,158	
Proceeds from sale of long-lived assets	2,912	—
	(1,455,333)	(2,072,058)
Effect of exchange rate differences on cash and restricted cash	(606)	598
Increase (decrease) in cash, cash equivalents and restricted cash	6,350	(1,531,848)
Cash, cash equivalents and restricted cash, beginning of year	59,423	1,591,271
Cash, cash equivalents and restricted cash, end of year	$ 65,773	$ 59,423

Supplemental disclosure of cash flow information:	**2018**	**2017**
Cash paid during the year for interest expense	$ 155,309	$ 166,773
Cash paid during the year for income taxes	$ 9,652	$ 8,633
Non-cash financing and investing activities:		
Property, plant and equipment acquisitions in accruals	$ 45,154	$ 112,959
Issuance of common shares under dividend reinvestment plan and share-based compensation plans	$ 65,767	$ 38,724
Issuance of common shares upon conversion of convertible debentures	$ 468	$ 846,271
Acquisition of equity investments in exchange for loan receivable and property, plant and equipment	$ 13,092	$ 5,368

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 Utilities Group and the Liberty Power Group. 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; the Liberty Power Group ("Liberty Power Group") owns and operates a diversified portfolio of non-regulated renewable and thermal electric generation assets. APUC also owns a 41.5% equity interest in Atlantica Yield plc ("Atlantica") (NASDAQ: AY), a company that acquires, owns and manages a diversified international portfolio of contracted renewable energy, power generation, electric transmission and water assets.

1. Significant accounting policies

(a) Basis of preparation

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

(b) Basis of consolidation

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

(c) Business combinations, intangible assets and goodwill

The Company accounts for acquisitions of entities or assets that meet the definition of a business as business combinations. The determination of whether the definition of a business has been met for a development stage project depends on the concentration of assets, 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 acquisition costs.

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

Goodwill represents the excess of the purchase price of an acquired business over the fair value of the net assets acquired. Goodwill is 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").

1. Significant accounting policies (continued)

(d) Accounting for rate regulated operations (continued)

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

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

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

(g) Accounts receivable

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

(h) Fuel and natural gas in storage

Fuel and natural gas in storage is reflected at weighted average cost or first-in-first-out as required by regulators and represents fuel, natural gas and liquefied natural gas that will be utilized in the ordinary course of business of the gas utilities and some generating facilities. Existing rate orders (note 7(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.

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

1. Significant accounting policies (continued)

(j) Property, plant and equipment

Property, plant and equipment are recorded at cost. Capitalization of development projects begins when management, 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.

	2018	2017
Interest capitalized on non-regulated property	$ 1,434	$ 4,325
AFUDC capitalized on regulated property:		
Allowance for borrowed funds	1,684	1,297
Allowance for equity funds	2,728	2,335
Total	$ 5,846	$ 7,957

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 12(a)) but where the advance repayment period has expired. These contributions are recorded as a reduction in the cost of utility assets and are amortized at the rate of the related asset as a reduction to depreciation expense. 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.

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

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	
	2018	2017	2018	2017
Generation	3 - 60	3 - 60	33	33
Distribution	5 - 100	5 - 100	40	40
Equipment	5 - 43	5 - 43	10	10

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

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.

(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).

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.

1. Significant accounting policies (continued)

(m) Variable interest entities (continued)

Total net book value of generating assets and long-term debt of these facilities amounts to $59,288 (2017 - $67,398) and $22,263 (2017 - $28,628), respectively. The portion of long-term debt which has recourse to the Company is $nil (2017 - $3,109). The financial performance of these facilities reflected on the consolidated statements of operations includes non-regulated energy sales of $17,232 (2017 - $17,508), operating expenses and amortization of $4,634 (2017 - $4,289) and interest expense of $1,258 (2017 - $2,755).

(n) Long-term investments and notes receivable

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

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

The components of net periodic benefit cost other than the service cost component are included in pension and post-employment non-service costs 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; a restricted share unit ("RSU") plan and a performance share unit ("PSU") plan. Equity classified awards are measured at the grant date fair value of the award. The Company estimates grant date fair value of options using the Black-Scholes option pricing model. The fair value is recognized over the vesting period of the award granted, adjusted for estimated forfeitures. The compensation cost is recorded as administrative expenses in the consolidated statements of operations and additional paid-in capital in equity. Additional paid-in capital is reduced as the awards are exercised, and the amount initially recorded in additional paid-in capital is credited to common shares.

(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 ("LLCs") 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 LLCs and partnership 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 17).

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 and presented as redeemable non-controlling interests on the consolidated balance sheets. The Company records temporary equity at issuance based on cash received less any transaction costs. As needed, the Company reevaluates the classification of its redeemable instruments, as well as the probability of redemption. If the redemption amount is probable or currently redeemable, the Company records the instruments at their redemption value. Increases or decreases in the carrying amount of a redeemable instrument are recorded within deficit. When the redemption feature lapses or other events cause the classification of an equity instrument as temporary equity to be no longer required, the existing carrying amount of the equity instrument is reclassified to permanent equity at the date of the event that caused the reclassification.

(s) Recognition of revenue

The Company accounts for revenue in accordance with ASC Topic 606, *Revenue from Contracts with Customers*, which was adopted on January 1, 2018 using the modified retrospective method, applied to contracts that are not completed at the date of initial application. Results for 2018 are presented under Topic 606, while prior period amounts are not adjusted and continue to be reported in accordance with the Company's historical accounting under Topic 605. The adoption of the new standard resulted in an adjustment of $2,488 or $1,860 net of taxes to increase opening retained earnings for previously deferred revenue related to the Empire fiber business.

Revenue is recognized when control of the promised goods or services is transferred to the Company's customers in an amount that reflects the consideration the Company expects to be entitled to in exchange for those goods or services.

Refer to note 20, Segmented information for details of revenue disaggregation by business units.

Liberty Utilities Group revenue

Liberty Utilities Group revenues consist primarily of the distribution of electricity, natural gas, and water.

Revenue related to utility electricity and natural gas sales and distribution is recognized over time as the energy is delivered. At the end of each month, the electricity and natural gas delivered to the customers from the date of their last meter read to the end of the month is estimated and the corresponding unbilled revenue is recorded. These estimates of unbilled revenue and sales are based on the ratio of billable days versus unbilled days, amount of electricity or natural gas procured during that month, historical customer class usage patterns, weather, line loss, unaccounted-for gas and current tariffs. Unbilled receivables are typically billed within the next month. Some customers elect to pay their bill on an equal monthly plan. As a result, in some months cash is received in advance of the delivery of electricity. Deferred revenue is recorded for that amount. The amount of revenue recognized in the period from the balance of deferred revenue is not significant.

Water reclamation and distribution revenue is recognized over time when water is processed or delivered to customers. At the end of each month, the water delivered and wastewater collected from the customers from the date of their last meter read to the end of the month 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. Unbilled receivables are typically billed within the next month.

The majority of Liberty Utilities Group's contracts have a single performance obligation that represents a promise to transfer to the customer a series of distinct goods that are substantially the same and that have the same pattern of transfer to the customer. The Company's performance obligation is satisfied over time as electricity, natural gas or water is delivered.

On occasion, a utility is permitted to implement new rates that have not been formally approved by the regulatory commission, which are subject to refund. The Company recognizes revenue based on the interim rate and if needed, establishes a reserve for amounts that could be refunded based on experience for the jurisdiction in which the rates were implemented.

1. Significant accounting policies (continued)

(s) Recognition of revenue (continued)

Liberty Utilities Group revenue (continued)

Revenue for certain of the Company's regulated utilities is subject to alternative revenue programs approved by their respective regulators. Under these programs, the Company charges approved annual delivery revenue on a systematic basis over the fiscal year. As a result, the difference between delivery revenue calculated based on metered consumption and approved delivery revenue is disclosed as alternative revenue in note 20, Segmented information and is recorded as a regulatory asset or liability to reflect future recovery or refund, respectively, from customers (note 7). The amount subsequently billed to customers is recorded as a recovery of the regulatory asset.

Liberty Power Group revenue

Liberty Power Group's revenue consists primarily of the sale of electricity, capacity, and renewable energy credits.

Revenue related to the sale of electricity is recognized over time as the electricity is delivered. The electricity represents a single performance obligation that represents a promise to transfer to the customer a series of distinct goods that are substantially the same and that have the same pattern of transfer to the customer.

Progress towards satisfaction of the single performance obligation is measured using an output method based on units produced and delivered within the production month.

Revenues related to the sale of capacity are recognized over time as the capacity is provided. The nature of the promise to provide capacity is that of a stand-ready obligation. The capacity is generally expressed in monthly volumes and prices. The capacity represents a single performance obligation that represents a promise to transfer to the customer a series of distinct services that are substantially the same and that have the same pattern of transfer to the customer. Progress towards satisfaction of the single performance obligation is measured using an output method based on time elapsed.

Qualifying renewable energy projects receive renewable energy credits ("RECs") and solar renewable energy credits ("SRECs") for the generation and delivery of renewable energy to the power grid. The energy credit certificates represent proof that 1 MW of electricity was generated from an eligible energy source. The RECs and SRECs can be traded and the owner of the RECs or SRECs can claim to have purchased renewable energy. RECs and SRECs are primarily sold under fixed contracts, and revenue for these contracts is recognized at a point in time, upon generation of the associated electricity. Any RECs or SRECs generated above contracted amounts are held in inventory, with the offset recorded as a decrease in operating expenses.

The majority of Liberty Power Group's contracts with customers are bundled arrangements of multiple performance obligations: electricity, capacity, and RECs.

The Company has elected to apply the invoicing practical expedient to the electricity and capacity in the Liberty Power Group contracts. The Company does not disclose the value of unsatisfied performance obligations for these contracts as revenue is recognized at the amount to which the Company has the right to invoice for services performed.

Revenue is recorded net of sales taxes.

(t) Foreign currency translation

APUC's reporting currency is the U.S. dollar. Within these consolidated financial statements, we denote any amounts denominated in Canadian dollars with "C$" immediately prior to the stated amount.

The Company's Canadian operations are determined to have the Canadian dollar as their functional currency since the preponderance of operating, financing and investing transactions are denominated in Canadian dollars. The financial statements of these operations are translated into U.S. dollars using the current rate method, whereby assets and liabilities are translated at the rate prevailing at the balance sheet date, and revenue and expenses are translated using average rates for the period. Unrealized gains or losses arising as a result of the translation of the financial statements of these entities are reported as a component of OCI and are accumulated in a component of equity on the consolidated balance sheets, and are not recorded in income unless there is a complete or substantially complete sale or liquidation of the investment.

1. Significant accounting policies (continued)

(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 18). 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, interest rate risk and price risk exposures associated with sales of generated electricity.

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.

1. Significant accounting policies (continued)

(v) Financial instruments and derivatives (continued)

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 2018-14, *Compensation—Retirement Benefits—Defined Benefit Plans—General (Subtopic 715-20): Disclosure Framework—Changes to the Disclosure Requirements for Defined Benefit Plans* as part of the disclosure framework project. This update removed certain disclosure requirements regarding AOCI expected to be recognized in income, related party transactions, and certain sensitivity analyses with respect to health care cost trends. This update also added disclosure requirements around the weighted-average interest crediting rates for cash balance plans and explanations for significant gains or losses in the reporting period. The early adoption of this ASU did not have a significant impact on the Company's consolidated financial statements.

The FASB issued ASU 2018-13, *Fair Value Measurement (Topic 820): Disclosure Framework — Changes to the Disclosure Requirements for Fair Value Measurement* as part of the disclosure framework project. This update removed certain disclosure requirements from Topic 820 including the amount of and reasons for transfers between Level 1 and Level 2 measurements, the policy for timing of transfers between levels, and the valuation processes for Level 3 measurements. This update also clarified disclosure requirements relating to measurement uncertainty, and added disclosure requirements for Level 3 measurements, specifically around the changes in unrealized gains and losses included in other comprehensive income and the range and weighted average of significant unobservable inputs. The early adoption of this ASU did not have a significant impact on the Company's consolidated financial statements.

The FASB issued ASU 2018-09, *Codification Improvements* to clarify the Codification and correct unintended application of guidance that is not expected to have a significant impact on current accounting practice. The adoption of this ASU had no impact on the Company's consolidated financial statements.

The FASB issued ASU 2018-03, *Technical Corrections and Improvements to Financial Instruments — Overall (Subtopic 825-10): Recognition and Measurement of Financial Assets and Financial Liabilities* to clarify the Codification and to correct unintended application of the guidance. The Company adopted this pronouncement concurrently with the adoption of ASU 2016-01. The adoption of this update had no impact on the Company's consolidated financial statements.

The FASB issued ASU 2018-02, *Income Statement—Reporting Comprehensive Income (Topic 220): Reclassification of Certain Tax Effects from Accumulated Other Comprehensive Income* ("AOCI") to allow a reclassification from AOCI to retained earnings for stranded tax effects resulting from the Tax Cuts and Jobs Act. The Company early adopted this pronouncement as of January 1, 2018, and as a result, a net amount of $10,625 was reclassified out of AOCI and recorded as an increase to accumulated deficit as at that date.

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 adoption of this update had no impact on the Company's consolidated financial statements.

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 also only allows the service cost component to be eligible for capitalization when applicable. The Company adopted this guidance effective January 1, 2018. The Company's regulated operations only capitalize the service costs component and therefore no regulatory to U.S. GAAP reporting differences exist. The Company applied the practical expedient for retrospective application on the consolidated statements of operations (note 10).

2. Recently issued accounting pronouncements (continued)

(a) Recently adopted accounting pronouncements (continued)

The FASB issued ASU 2017-05, *Other Income—Gains and Losses from the Derecognition of Non-financial 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 and provides additional guidance on partial sales of non-financial assets. The adoption of this update had no impact on the Company's consolidated financial statements.

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 Company follows the pronouncements of this update as of January 1, 2018.

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. Prior to the adoption of this update, the Company presented changes in restricted cash as investing activities 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. The adoption of this update had no impact on the Company's consolidated financial statements.

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 adoption of this update had no impact on the Company's consolidated financial statements.

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 adoption of this update had no significant impact on the Company's consolidated financial statements.

(b) Recently issued accounting guidance not yet adopted

The FASB issued ASU 2018-19: *Codification Improvements to Topic 326, Financial Instruments — Credit Losses* as part of its project to correct unintended application of accounting standards. The amendments clarify that receivables arising from operating leases are not within the scope of ASC 326-20. Instead, impairment of receivables arising from operating leases should be accounted for in accordance with Topic 842, *Leases*. The amendments in this Update are effective the same date as Update 2016-13, which is effective for fiscal years beginning after December 15, 2019, including interim periods within those fiscal years. The Company is currently assessing the impact of this Update.

The FASB issued ASU 2018-18, *Collaborative Arrangements (Topic 808): Clarifying the Interaction between Topic 808 and Topic 606* to reduce diversity in practice on how entities account for transactions on the basis of different views of the economics of a collaborative arrangement. The Update clarifies that the arrangement should be accounted for under ASC 606 when a participant is a customer in the context of a unit of account, adds unit of account guidance in ASC 808 that is consistent with ASC 606, and precludes the recognition of revenue from a collaborative arrangement with ASC 606 revenue if the participant is not directly related to sales to third parties. The amendments in this Update are effective for fiscal years beginning after December 15, 2019, and interim periods within those years. Early adoption is permitted. The Company is currently assessing the impact of this Update.

The FASB issued ASU 2018-17, *Consolidation (Topic 810): Targeted Improvements to Related Party Guidance for Variable Interest Entities* to improve general purpose financial reporting. The Update clarifies that indirect interests held through related parties in common control arrangements should be considered on a proportional basis for determining whether fees paid to decision makers and service providers are variable interests. The amendments in the Update are effective for fiscal years beginning after December 15, 2019 and interim periods within those fiscal years. The amendments are required to be applied retrospectively with a cumulative-effect adjustment to retained earnings. Early adoption is permitted. The Company is currently assessing the impact of this Update.

2. Recently issued accounting pronouncements (continued)

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

The FASB issued ASU 2018-16, *Derivatives and Hedging (Topic 815): Inclusion of the Secured Overnight Financing Rate ("SOFR") Overnight Index Swap ("OIS") Rate as a Benchmark Interest Rate for Hedge Accounting Purposes* to identify a suitable alternative to the U.S. dollar LIBOR that is more firmly based on actual transactions in a robust market. This Update permits the use of the OIS rate based on SOFR as a U.S. benchmark interest rate for hedge accounting purposes. The amendments in this Update are required to be adopted concurrently with the amendments in Update 2017-12, which is required for all fiscal years beginning after December 15, 2018. The amendments will be adopted prospectively for qualifying new or redesignated hedging relationships entered into after the date of adoption.

The FASB issued ASU 2018-15, *Intangibles—Goodwill and Other—Internal-Use Software (Subtopic 350-40)*: Customers Accounting for Implementation Costs Incurred in a Cloud Computing Arrangement that is a Service Contract to provide additional guidance to address diversity in practice. This update aligns the requirements for capitalizing implementation costs incurred in a hosting arrangement that is a service contract with the requirements for capitalizing implementation costs incurred to develop or obtain internal-use software. Therefore, an entity will follow the guidance in Subtopic 350-40 to determine which implementation costs to capitalize as an asset related to the service contract and which costs to expense. In addition, the capitalized implementation costs are required to be expensed over the term of the hosting arrangement. This update is effective for fiscal years beginning after December 15, 2019, including interim periods within those fiscal years. Early adoption is permitted in any interim period. The amendments can either be applied retrospectively or prospectively to all implementation costs incurred after the date of adoption. The Company is currently assessing the impacts of this update.

The FASB issued ASU 2018-07, *Compensation — Stock Compensation (Topic 718): Improvements to Non-employee Share-Based Payment Accounting* to expand the scope of Topic 718 to include share-based payment transactions for acquiring goods and services from non-employees. This update changes the measurement basis and date of non-employee share-based payment awards and also makes amendments to how to measure non-employee awards with performance conditions. The update is effective for fiscal years beginning after December 15, 2018, including interim periods within those fiscal years. No impact on the consolidated financial statements is expected from the adoption 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. The Company does not expect a significant impact on the consolidated financial statements as a result of the adoption of this update.

The FASB issued ASU 2017-04, *Business Combinations (Topic 350): Intangibles — Goodwill and Other (Topic 350): Simplifying the Test for Goodwill Impairment*. The update is intended to simplify how an entity is required to test goodwill for impairment by eliminating Step 2 from the goodwill impairment test. Step 2 measures a goodwill impairment loss by comparing the implied fair value of a reporting unit's goodwill with the carrying amount of that goodwill. The standard is effective for fiscal years and interim periods beginning after December 15, 2019.

The 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.

2. Recently issued accounting pronouncements (continued)

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

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 that 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 issued a further update to ASC Topic 842 in ASU 2018-11 to allow companies to elect not to restate their comparative periods in the period of adoption when transitioning to the standard. The FASB has also issued further codification and narrow-scope improvements to ASC Topic 842 to correct and clarify specific aspects of the guidance. The standard is effective for fiscal years and interim periods beginning after December 15, 2018.

The Company is in the process of finalizing its assessment of the financial, operational, and business processes impacts of the new lease accounting standard. At this point, the Company expects that the adoption of Topic 842 will not have a material impact on the consolidated financial statements. The Company intends to implement new processes and procedures for the identification, analysis, and measurement of new lease contracts on a prospective basis. A new software solution is being implemented to assist with contract management, information tracking, and measurement as it relates to the new standard. The Company intends to elect the following practical expedients as part of its adoption:

1. "Package of three" practical expedient that permits the Company not to reassess the scope, classification and initial direct costs of its expired and existing leases;
2. Land easements practical expedient that permits the Company not to reassess the accounting for land easements previously not accounted for under ASC 840; and
3. Hindsight practical expedient that allows the Company to use hindsight in determining the lease term for existing contracts.

In addition, the Company will make an accounting policy election to not recognize a lease liability or right-of-use asset on its consolidated balance sheets for short-term leases (lease term less than 12 months).

The Company intends to adopt the lease accounting standard retrospectively at the beginning of the period of adoption through a cumulative-effect adjustment.

3. Business acquisitions and development projects

(a) Agreement to acquire Enbridge Gas New Brunswick Limited Partnership

On December 4, 2018, the Company entered into an agreement to acquire Enbridge Gas New Brunswick Limited Partnership ("New Brunswick Gas"). New Brunswick Gas is a regulated utility that provides natural gas to approximately 12,000 customers and operates approximately 800 km of natural gas distribution pipeline. The total purchase price for the transaction is C$331,000, subject to certain closing adjustments. Closing of the transaction remains subject to regulatory approval and is expected in 2019.

(b) Agreement to acquire St. Lawrence Gas Company, Inc.

On August 31, 2017, the Company entered into an 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 $70,000, less total third-party debt of SLG outstanding at closing, subject to certain closing adjustments. Closing of the transaction remains subject to regulatory approval and is expected to occur in 2019.

(c) Approval to acquire the Perris Water Distribution System

On August 10, 2017, the Company's Board of Directors approved the acquisition of two water distribution systems serving customers from the City of Perris, California. The anticipated purchase price of $11,500 is expected to be established as rate base during the regulatory approval process. The City of Perris residents voted to approve the sale on November 7, 2017. The Liberty Utilities Group filed an application requesting approval for the acquisition of the assets of the water utilities with the California Public Utility Commission on May 8, 2018. Final approval is expected in 2019.

(d) Great Bay Solar Facility

The Great Bay Solar Facility consists of a 75 MWac solar powered generating facility in Somerset County, Maryland. As of December 31, 2017, three sites had been fully synchronized with the power grid, while the last site was placed in service in March 2018. Commercial operations as defined by the power purchase agreement was reached for all sites by March 29, 2018.

The Great Bay Solar Facility is controlled by a subsidiary of APUC (Great Bay Holdings, LLC). The Class A partnership units are owned by a third-party tax equity investor who funded $42,750 in 2017 with the remaining amount of $15,250 received in 2018. Through its partnership interest, the tax equity investor will receive the majority of the tax attributes associated with the project. The Company accounts for this interest as "Non-controlling interest" on the consolidated balance sheets.

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

3. Business acquisitions and development projects (continued)

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

Working capital	$ 41,292
Property, plant and equipment	2,058,867
Goodwill	752,418
Regulatory assets	236,933
Other assets	43,609
Long-term debt	(907,547)
Regulatory liabilities	(145,594)
Pension and other post-employment benefits	(78,204)
Deferred income taxes liability, net	(418,855)
Other liabilities	(76,532)
Total net assets acquired	$ 1,506,387
Cash and cash equivalents	1,742
Total net assets acquired, net of cash and cash equivalents	$ 1,504,645

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.

(f) Luning Solar Facility

Luning Utilities (Luning Holdings) LLC (the “Luning Holdings”) is owned by the Calpeco Electric System. The 50 MWac 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 $7,826 as of December 31, 2016 and $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 17). Redemption is not considered probable as of December 31, 2018.

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

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

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	$ 152
Property, plant and equipment	110,857
Asset retirement obligation	(546)
Non-controlling interest (tax equity)	(38,633)
Total net assets acquired	$ 71,830

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 $2,454 on November 29, 2016 and approximately $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.

4. Accounts receivable

Accounts receivable as of December 31, 2018 include unbilled revenue of $79,742 (2017 - $78,289) from the Company's regulated utilities. Accounts receivable as of December 31, 2018 are presented net of allowance for doubtful accounts of $5,281 (2017 - $5,555).

5. Property, plant and equipment

Property, plant and equipment consist of the following:

2018

	Cost	Accumulated depreciation	Net book value
Generation	$ 2,470,279	$ 450,230	$ 2,020,049
Distribution	4,455,935	521,236	3,934,699
Land	73,773	—	73,773
Equipment and other	88,757	41,295	47,462
Construction in progress			
Generation	104,996	—	104,996
Distribution	212,579	—	212,579
	$ 7,406,319	$ 1,012,761	$ 6,393,558

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

5. Property, plant and equipment (continued)

2017

	Cost	Accumulated depreciation	Net book value
Generation	$ 2,382,279	$ 394,509	$ 1,987,770
Distribution	4,205,823	388,859	3,816,964
Land	71,689	—	71,689
Equipment and other	91,233	37,104	54,129
Construction in progress			
Generation	209,979	—	209,979
Distribution	164,366	—	164,366
	$ 7,125,369	$ 820,472	$ 6,304,897

Generation assets include cost of $104,107 (2017 - $113,822) and accumulated depreciation of $34,916 (2017 - $34,908) related to facilities under capital lease or owned by consolidated VIEs. Depreciation expense of facilities under capital lease was $1,987 (2017 - $1,633).

Distribution assets include cost of $1,383,960 (2017 - $1,341,716) and accumulated depreciation of $69,960 (2017 - $28,809) related to regulated generation and transmission assets. Distribution assets include cost of $546,332 (2017 - $493,570) and accumulated depreciation of $42,476 (2017 - $8,578) related to commonly owned facilities (note 1(k)). Total expenditures for the year ended December 31, 2018 were $75,427 (2017 - $79,657). Distribution assets include cost of $3,076 (2017 - $3,076) and accumulated depreciation of $669 (2017 - $336) related to assets under capital lease. 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, 2018, contributions received in aid of construction of $6,057 (2017 - $12,742) have been credited to the cost of the assets.

6. Intangible assets and goodwill

Intangible assets consist of the following:

2018	Cost	Accumulated amortization	Net book value
Power sales contracts	$ 60,775	$ 36,063	$ 24,712
Customer relationships	26,795	9,476	17,319
Interconnection agreements	13,847	884	12,963
	$ 101,417	$ 46,423	$ 54,994

2017	Cost	Accumulated amortization	Net book value
Power sales contracts	$ 56,540	$ 36,878	$ 19,662
Customer relationships	26,799	8,836	17,963
Interconnection agreements	14,181	703	13,478
	$ 97,520	$ 46,417	$ 51,103

Estimated amortization expense for intangible assets for the next year is $2,093, $2,265 in year two, $2,430 in year three, $2,400 in year four and $1,820 in year five.

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

6. Intangible assets and goodwill (continued)

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

Balance, January 1, 2017	$	228,377
Business acquisitions		752,418
Divestiture of operating entity (note 21(a))		(26,513)
Balance, December 31, 2018 and 2017	$	954,282

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.

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

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 $'000	Effective Date
Empire Electric System	Missouri	Tax Reform docket	$(17,837)	Prospective decrease in annual revenue effective August 30, 2018 due to the reduction of the U.S. federal corporate income tax rate.
EnergyNorth Gas System	New Hampshire	General Rate Review	$10,711	Effective May 1, 2018. The regulator also approved a one-time recoupment of $1,326 for the difference between the final rates and temporary rates granted on July 1, 2017. In November 2018, EnergyNorth received an order for rehearing clarifying the implementation of the decoupling mechanism that was approved and resolving the impacts of tax reform through the rehearing. The net result was a one-time decrease to the recoupment of $280.
Missouri Gas System	Missouri	General Rate Review	$4,600	Effective July 1, 2018
Peach State Gas System	Georgia	GRAM	$2,367	Effective February 1, 2019
New England Natural Gas System	Massachusetts	Gas System Enhancement Plan	$3,676	Effective May 1, 2018
New England Gas System	Massachusetts	GRC	$8,300	$7,800 effective March 1, 2016 $500 effective March 1, 2017
Calpeco Electric System	California	Post-Test Year Adjustment Mechanism	$2,175	January 1, 2018
Midstates Gas System	Illinois	GRC	$2,200	June 7, 2017
Various	Various	Various	$3,048	Other rate reviews closed: Missouri Water ($1,015), and Litchfield Park Water & Sewer ($617), Park Water 2018 increase ($1,531), Georgia 2018 Gas Rate Adjustment Mechanism (-$115)

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

7. Regulatory matters (continued)

Regulatory assets and liabilities consist of the following:

	2018	2017
Regulatory assets		
Environmental remediation (a)	$ 82,295	$ 82,711
Pension and post-employment benefits (b)	125,959	105,712
Debt premium (c)	48,847	57,406
Fuel and commodity costs adjustments (d)	26,310	34,525
Rate adjustment mechanism (e)	36,484	35,813
Clean Energy and other customer programs (f)	22,269	20,582
Deferred construction costs (g)	13,986	14,344
Asset retirement (h)	21,048	16,080
Income taxes (i)	34,822	36,546
Rate review costs (j)	7,990	9,295
Other	30,464	28,512
Total regulatory assets	$ 450,474	$ 441,526
Less: current regulatory assets	(59,037)	(66,567)
Non-current regulatory assets	$ 391,437	$ 374,959
Regulatory liabilities		
Income taxes (i)	$ 323,384	$ 321,138
Cost of removal (k)	193,564	184,188
Rate base offset (l)	10,900	13,214
Fuel and commodity costs adjustments (d)	23,517	23,543
Deferred compensation received in relation to lost production (m)	6,897	9,398
Deferred construction costs - fuel related (g)	7,258	7,418
Pension and post-employment benefits (b)	877	10,082
Other	12,195	7,143
Total regulatory liabilities	$ 578,592	$ 576,124
Less: current regulatory liabilities	(39,005)	(37,687)
Non-current regulatory liabilities	$ 539,587	$ 538,437

(a) Environmental remediation

Actual expenditures incurred for the clean-up of certain former gas manufacturing facilities (note 12(b)) are recovered through rates over a period of 7 years and are subject to an annual cap.

(b) Pension and post-employment benefits

As part of certain business acquisitions, the regulators authorized a regulatory asset or liability being set up for the amounts of pension and post-employment benefits that have not yet been recognized in net periodic cost and were presented as AOCI prior to the acquisition. The balance is recovered through rates over the future service years of the employees at the time the regulatory asset was set up (an average of 10 years) or consistent with the treatment of OCI under ASC 712 *Compensation Non-retirement Post-employment Benefits* and ASC 715 *Compensation Retirement Benefits* before the transfer to regulatory asset occurred. The annual movements in AOCI for Empire's pension and OPEB plans (note 10(a)) are also reclassified to regulatory accounts since it is probable the unfunded amount of these plans will be afforded rate recovery. Finally, the regulators have also approved tracking accounts for a number of the utilities. The amounts recorded in these accounts occur when actual expenses differs from those adopted and recovery or 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 adjustments

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 23(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, New England Gas System, Midstates Natural Gas system, EnergyNorth Natural Gas System, and Granite State Electric System 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 reflect 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.

On June 1, 2018, the State of Missouri enacted legislation that, effective for tax years beginning on or after January 1, 2020, reduces the corporate income tax rate from 6.25% to 4%, among other legislative changes. A reduction of regulatory asset and an increase to regulatory liability was recorded for excess deferred taxes probable of being refunded to customers of $15,586.

The Tax Cuts and Jobs Act (the “Tax 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 in 2017 for excess deferred taxes probable of being refunded to customers of $327,947.

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

7. Regulatory matters (continued)

(i) Income taxes (continued)

As a result of the Tax Act enacted in 2017, regulators in the states where Liberty Utilities Group operates are contemplating the ratemaking implications of the reduction of federal tax rates from the legacy 35% tax rate and the new 21% federal statutory income tax rate effective January 2018. The Company is working with the regulators to identify the most appropriate way in each jurisdiction to address the impact of the Tax Act on cost of service based rates. As at December 31, 2018, the impact on regulated liability on account of ordered or probable orders related to the Tax Act was immaterial.

(j) Rate review costs

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

(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.

(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 review costs.

8. Long-term investments

Long-term investments consist of the following:

	2018	2017
Long-term investment in Atlantica carried at fair value (a)	$ 814,530	$ —
Notes receivable from equity investees (e)	$ 101,416	$ 30,060
Other long-term investments		
Equity-method investees		
AAGES (b)	2,622	—
Red Lily I Wind Facility (c)	15,705	18,174
Amherst Island Wind Project (d)	7,655	8,921
Other	4,510	5,172
	$ 30,492	$ 32,267
Other investments	3,870	5,004
Other long-term investments	34,362	37,271
Less: current portion	(1,407)	—
	$ 32,955	$ 37,271

Dividend income of $41,079 (2017 - $1,167) and equity loss of $1,609 (2017 - income $2,742) are included in Interest, dividend, equity and other income on the consolidated statements of operations.

8. Long-term investments (continued)

(a) Investment in Atlantica

On March 9, 2018, APUC purchased from Abengoa S.A. ("Abengoa") a 25% equity interest in Atlantica for a purchase price of $607,567, based on a price of $24.25 per ordinary share of Atlantica plus a contingent payment of up to $0.60 per-share payable two years after closing, subject to certain conditions. On November 27, 2018, APUC purchased from Abengoa an additional 16.5% equity interest in Atlantica for a purchase price of $345,000, based on a price of $20.90 per ordinary share of Atlantica comprised of a payment of approximately $305,000 drawn from the Company's credit facility for payment on closing and a holdback of $40,000 payable at a later date, subject to certain conditions. The Company transferred the Atlantica shares to AAGES (AY Holdings) B.V. ("AY Holdings"), a new entity controlled and consolidated by APUC. The Company has elected the fair value option under ASC 825, *Financial Instruments* to account for its investment in Atlantica, with changes in fair value reflected in the consolidated statements of operations. The difference between the purchase price and the value of the Atlantica shares based on the NASDAQ share price on the acquisition dates resulted in a combined immediate fair value loss of $139,864. A fair value gain of $1,907 was recorded for the period from acquisition to December 31, 2018 resulting in a net loss on fair value for the year of $137,957.

The Company also recorded dividend income of $39,263 from the Atlantica shares during the period from acquisition to December 31, 2018.

On November 28, 2018, Abengoa-Algonquin Global Energy Solutions B.V. ("AAGES B.V.") obtained a three year secured credit facility in the amount of $306,500 and subscribed to a preference share ownership interest in AY Holdings. The subscription proceeds were distributed by AY Holdings to the Company and used by the Company to repay the $305,000 drawn under the credit facility. The AAGES B.V. secured credit facility is collateralized through a pledge of the Atlantica shares held by AY Holdings. A collateral shortfall would occur if the net obligation as defined in the agreement would equal or exceed 50% of the market value of the Atlantica shares in which case the lenders would have the right to sell Atlantica stock to eliminate the collateral shortfall. APUC reflects the preference share ownership issued by AY Holdings as redeemable non-controlling interest (note 17).

(b) Investment in AAGES

APUC and Abengoa created AAGES B.V., AAGES Development Canada Inc. and AAGES Development Spain (collectively, the "AAGES entities") to identify, develop, and construct clean energy and water infrastructure assets with a global focus. Each partner initially contributed $5,000 to the AAGES entities. AAGES Development Canada Inc. and AAGES Development Spain are considered a VIE due to the level of equity at risk. The Company is not considered the primary beneficiary of AAGES Development Canada Inc. and AAGES Development Spain as the two partners have joint control and all decisions must be unanimous. As such, the Company is accounting for its investment in the joint ventures under the equity method. The AAGES entities contributed equity loss of $3,005 to the Company's consolidated financial results for the year ended December 31, 2018.

As of December 31, 2018, the Company's maximum exposure to loss of $7,509 related to AAGES Development Canada Inc. and AAGES Development Spain 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(e).

(c) Red Lily I Wind Facility

The Red Lily I Wind Facility (the "Partnership") is a 26.4 MW wind energy facility located in southeastern Saskatchewan. The Company owns a 75% equity interest in the Partnership.

Due to certain participating rights being held by the minority investor, the decisions which most significantly impact the economic performance of the Red Lily I Wind Facility 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 the Red Lily I Wind Facility, the Company accounts for the Partnership using the equity method. The Red Lily I Wind Facility contributed equity income of $1,637 (2017 - $2,139) to the Company's consolidated financial results for the year ended December 31, 2018.

8. Long-term investments (continued)

(d) Amherst Island Wind Project

APUC has a 50% interest in Windlectric Inc. ("Windlectric") which owns a 74.1 MW wind generating facility ("Amherst Island Wind Facility") in the Province of Ontario. Construction was completed during the second quarter of 2018 and sale of power under the power purchase agreement has started. Subsequent to year-end, the Company exercised its option to acquire the remaining common shares at a pre-agreed price. The acquisition is subject to regulatory approval expected to be obtained in 2019.

Windlectric is considered a VIE due to the level of equity at risk. 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, the Company accounts for its investment in the joint venture under the equity method. The interest capitalized during the year ended December 31, 2018 to the investment while the Amherst Island Wind Facility was under construction amounts to $739 (2017 - $1,115).

As at December 31, 2018, the net book value of property, plant and equipment of the joint venture was $308,825 while the third-party construction debt was $190,910 (2017 - $106,628). Windlectric contributed equity loss of $1,714 (2017 - nil) to the Company's consolidated financial results for the year ended December 31, 2018.

As of December 31, 2018, the Company's maximum exposure to loss of $192,052 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(e). Subsequent to year-end, the joint venture borrowed from the Company to repay in full the third-party construction debt.

(e) Development loans receivable from equity investees

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, 2018, the Company has a loan and credit support facility with Windlectric of $96,477 (2017 - $30,060). 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, 2018, the following credit support was outstanding on behalf of Windlectric: letters of credit and guarantees of obligations to the utilities under the power purchase agreement; a guarantee of the obligations under the wind turbine, transmission line, transformer, and other supply agreements; and, a guarantee of the obligations under the engineering, procurement, and construction management agreements. The value of the guarantee obligations is recognized under other long-term liabilities and as at December 31, 2018 is valued at $1,637 (2017 - $1,952) using a probability weighted discounted cash flow (level 3). The Company recognized interest income of $6,144 on the advances and credit support from the day Amherst Island Wind Facility achieved commercial operations to December 31, 2018.

As at December 31, 2018, the Company has a balance receivable from the AAGES entities of $4,940. As at December 31, 2018, the Company has issued $3,750 in letters of credit on behalf of AAGES. Subsequent to year-end, $1,750 was repaid under this credit support facility.

Following acquisition of control of Deerfield SponsorCo (note 8(f)(ii)), amounts advanced to the wind facility are eliminated on consolidation. The effects of foreign currency exchange rate fluctuations on these advances of a long-term investment nature are recorded in OCI from the date of acquisition.

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

8. Long-term investments (continued)

(f) Other transactions

i. Wataynikaneyap Power Transmission Project

Subsequent to year-end, APUC acquired a 9.8% ownership interest in the Wataynikaneyap Power Transmission Project, a transmission project that involves the development, construction and operation of a 1,800 km transmission line in Northwestern Ontario.

ii. Deerfield Wind Facility

The Company had a 50% equity interest in Deerfield Wind SponsorCo LLC ("Deerfield SponsorCo"), which indirectly owns a 149 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.

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(e)) 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	$	(10,808)
Property, plant and equipment		328,371
Construction loan		(261,952)
Asset retirement obligation		(2,092)
Deferred revenue		(1,156)
Deferred tax liability		(1,470)
Net assets acquired	$	50,893
Cash and cash equivalents	$	3,107
Net assets acquired, net of cash and cash equivalents	$	47,786

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

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

9. Long-term debt

Long-term debt consists of the following:

Borrowing type	Weighted average coupon	Maturity		Par value	2018	2017
Senior unsecured revolving credit facilities (a)	—	2019-2023		N/A	$ 97,000	$ 51,827
Senior unsecured bank credit facilities (b)	—	2019		N/A	321,807	134,988
Commercial paper (a)	—	2023		N/A	6,000	5,576
U.S. dollar borrowings						
Senior unsecured notes (c)	4.09%	2020-2047	$	1,225,000	1,218,680	1,217,797
Senior unsecured utility notes (d)	5.99%	2020-2035	$	222,000	240,161	246,560
Senior secured utility bonds (e)	4.75%	2020-2044	$	662,500	676,697	772,871
Subordinated unsecured notes (f)	6.88%	2078	$	287,500	278,771	—
Canadian dollar borrowings						
Senior unsecured notes (g)	4.43%	2020-2027	C$	650,669	474,764	623,223
Senior secured project notes	10.25%	2020-2027	C$	31,310	22,915	26,709
					$ 3,336,795	$ 3,079,551
Less: current portion					(13,048)	(12,364)
					$ 3,323,747	$ 3,067,187

Long-term debt issued at a subsidiary level (project notes or utility bonds) relating to a specific operating facility is generally collateralized by the respective facility with no other recourse to the Company. Long-term debt issued at a subsidiary level whether or not collateralized generally has certain financial covenants, which must be maintained on a quarterly basis. Non-compliance with the covenants could restrict cash distributions/dividends to the Company from the specific facilities.

Short-term obligations of $321,807 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 C$65,000 senior unsecured revolving bank credit facility to increase the commitments to C$165,000 and, on November 16, 2018, the Company extended the maturity from November 19, 2018 to November 19, 2019.

On February 23, 2018, the Liberty Utilities Group increased commitments under its credit facility to $500,000 and extended the maturity to February 23, 2023. Concurrent with this amendment, the Liberty Utilities Group closed Empire's credit facility. Liberty Utilities' credit facility will now be used as a backstop for Empire's commercial paper program and as a source of liquidity for Empire.

On October 6, 2017, the Liberty Power Group amended the terms of its C$350,000 senior unsecured revolving bank credit facility to increase the commitments to $500,000 and extended the maturity from July 31, 2019 to October 6, 2022. The Liberty Power Group extended the maturity of its senior unsecured revolving bank credit facility from October 6, 2022 to October 6, 2023. On February 16, 2018, the Liberty Power Group increased availability under its revolving letter of credit facility to $200,000 and extended the maturity to January 31, 2021.

9. Long-term debt (continued)

(b) Senior unsecured bank credit facilities

On December 21, 2017, the Company entered into a $600,000 term credit facility with two Canadian banks maturing on December 21, 2018. On March 7, 2018, the Company drew $600,000 under this facility. On December 19, 2018, the Company extended the maturity of this facility to June 21, 2019. The balance drawn as at December 31, 2018 is $186,807.

On December 30, 2016, in connection with the acquisition of Empire (note 3(e)), the Company drew $1,336,440 from its Acquisition Facility. Following receipt of the Final Instalment from the convertible debentures on February 7, 2017 (note 12(h)) and the senior notes financing on March 24, 2017 (note 9(d)), the Company fully repaid the Acquisition Facility.

As at December 31, 2018, the Company had drawn $135,000 on its Corporate Term Credit Facility which matures on July 5, 2019.

(c) Senior unsecured notes

On March 24, 2017, the Liberty Utilities Group's debt financing entity issued $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%.

(d) Senior unsecured utility notes

On January 1, 2017, in connection with the acquisition of Empire (note 3(e)), the Company assumed $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%.

(e) Senior secured utility bonds

On January 1, 2017 in connection with the acquisition of Empire (note 3(e)), the Company assumed $733,000 in secured utility bonds. 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%. On June 1, 2018, the Company repaid, upon its maturity, a $90,000 secured utility note.

In June 2017, outstanding bonds payable for the Park Water Systems in the amount of $63,000 were repaid using proceeds from the Mountain Water condemnation discussed in note 21(a).

(f) Subordinated unsecured notes

On October 17, 2018, the Company completed the issuance of $287,500 unsecured, 6.875% fixed-to-floating subordinated notes (“subordinated notes”) maturing on October 17, 2078. The subordinated notes are listed on the New York Stock Exchange ("NYSE") under the ticker symbol "AQNA". Beginning on October 17, 2023, and on every quarter thereafter that the subordinated notes are outstanding (the "interest reset date") until October 17, 2028, the subordinated notes will be reset at an interest rate of the three-month LIBOR plus 3.677%, payable in arrears. Beginning on October 17, 2028, and on every interest reset date until October 17, 2043, the subordinated notes will be reset at an interest rate of the three-month LIBOR plus 3.927%, payable in arrears. Beginning on October 17, 2043, and on every interest reset date until October 17, 2078, the subordinated notes will be rest at an interest rate of the three-month LIBOR plus 4.677%, payable in arrears.

The Company may elect, at its sole option, to defer the interest payable on the subordinated notes on one or more occasions for up to five consecutive years. Deferred interest will accrue, compounding on each subsequent interest payment date, until paid. Additionally, on or after October 17, 2023, the Company may, at its option, redeem the subordinated notes, at a redemption price equal to 100% of the principal amount, together with accrued and unpaid interest.

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

9. Long-term debt (continued)

(g) Canadian dollar senior unsecured notes

Subsequent to year-end, the Liberty Power Group issued C$300,000 senior unsecured notes bearing interest at 4.60% with a maturity date of January 29, 2029. The notes were sold at a price of C$99.952 per C$100.00 principal amount. Concurrent with the financing, the Liberty Power Group unwound and settled the related forward-starting interest rate swap on a notional bond of C$135,000 (note 23(b)(ii)).

On July 25, 2018, the Company repaid, upon its maturity, a C$135,000 unsecured note.

On January 17, 2017, the Liberty Power Group issued C$300,000 senior unsecured notes bearing interest at 4.09% with a maturity date of February 17, 2027. The notes were sold at a price of C$99.929 per C$100.00 principal amount.

As of December 31, 2018, the Company had accrued $33,822 in interest expense (2017 - $33,064). Interest expense on the long-term debt in 2018 was $150,262 (2017 - $142,791).

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

2019	2020	2021	2022	2023	Thereafter	Total
$ 334,855	$ 308,917	$ 111,880	$ 343,737	$ 481,859	$ 1,740,471	$ 3,321,719

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 2018 were $8,446 (2017 - $7,232).

In conjunction with the utility acquisitions, the Company assumes defined benefit pension, supplemental executive retirement plans and OPEB plans for qualifying employees in the related acquired businesses. The legacy plans of the electricity and gas utilities are non-contributory defined pension plans covering substantially all employees of the acquired businesses. Benefits are based on each employee's years of service and compensation. The Company also provides a defined benefit cash balance pension plan covering substantially all its new employees and current employees at its water utilities, under which employees are credited with a percentage of base pay plus a prescribed interest rate credit. The OPEB plans provide health care and life insurance coverage to eligible retired employees. Eligibility is based on age and length of service requirements and, in most cases, retirees must cover a portion of the cost of their coverage.

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

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

(a) Net pension and OPEB obligation

The following table sets forth the projected benefit obligations, fair value of plan assets, and funded status of the Company's plans as of December 31:

	Pension benefits		OPEB	
	2018	2017	2018	2017
Change in projected benefit obligation				
Projected benefit obligation, beginning of year	$ 523,743	$ 247,246	$ 176,975	$ 61,888
Projected benefit obligation assumed from business combination	—	256,486	—	97,761
Service cost	15,481	14,747	5,791	4,838
Interest cost	18,717	20,191	6,727	6,642
Actuarial (gain) loss	(29,845)	35,696	(14,800)	10,263
Contributions from retirees	—	—	1,920	1,821
Gain on curtailment	(1,875)	(849)	—	(4)
Benefits paid	(49,429)	(49,774)	(8,288)	(6,234)
Projected benefit obligation, end of year	$ 476,792	$ 523,743	$ 168,325	$ 176,975
Change in plan assets				
Fair value of plan assets, beginning of year	403,945	176,040	130,487	21,701
Plan assets acquired in business combination	—	184,510	—	91,532
Actual return on plan assets	(36,987)	63,250	(10,603)	19,733
Employer contributions	21,570	29,919	2,068	2,068
Benefits paid	(49,429)	(49,774)	(6,410)	(4,547)
Fair value of plan assets, end of year	$ 339,099	$ 403,945	$ 115,542	$ 130,487
Unfunded status	$ (137,693)	$ (119,798)	$ (52,783)	$ (46,488)
Amounts recognized in the consolidated balance sheets consists of:				
Non-current assets	—	—	3,161	3,936
Current liabilities	(872)	(861)	(850)	(1,172)
Non-current liabilities	(136,821)	(118,937)	(55,094)	(49,252)
Net amount recognized	$ (137,693)	$ (119,798)	$ (52,783)	$ (46,488)

The accumulated benefit obligation for the pension plans was $439,458 and $490,108 as of December 31, 2018 and 2017, respectively.

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

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

(a) Net pension and OPEB obligation (continued)

Information for pension and OPEB plans with an accumulated benefit obligation in excess of plan assets:

	Pension		OPEB	
	2018	2017	2018	2017
Accumulated benefit obligation	439,458	462,943	163,375	171,175
Fair value of plan assets	339,099	376,276	107,430	121,561

Information for pension and OPEB plans with a projected benefit obligation in excess of plan assets:

	Pension		OPEB	
	2018	2017	2018	2017
Projected benefit obligation	476,791	523,743	163,375	171,175
Fair value of plan assets	339,099	403,945	107,430	121,561

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 21(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 $2,354 recorded in OCI and a curtailment gain of $853 recorded against the loss on long-lived assets.

In 2018, the Company permanently froze the accrual of benefits for participants in Park Water's existing pension plan. Subsequent to the effective date, these employees began accruing benefits under the Company's cash balance plan. The plan amendments resulted in an decrease to the projected benefit obligation of $1,875 which is recorded as a prior service credit in OCI.

Change in AOCI (before tax)	Pension		OPEB	
	Actuarial losses (gains)	Past service gains	Actuarial losses (gains)	Past service gains
Balance, January 1, 2017	$ 27,572	$ (5,617)	$ (3,861)	$ (732)
Additions to AOCI	(2,652)	—	(3,066)	—
Reclassification to regulatory accounts (note 7(b))	1,136	—	3,515	—
Amortization in current period	(928)	622	230	262
Balance, December 31, 2017	$ 25,128	$ (4,995)	$ (3,182)	$ (470)
Additions to AOCI	34,916	(1,875)	3,254	—
Reclassification to regulatory accounts (note 7(b))	(22,166)	—	(14,232)	—
Amortization in current period	(1,074)	649	272	262
Gain (loss) on plan settlements	(2,547)	—	—	—
Balance, December 31, 2018	$ 34,257	$ (6,221)	$ (13,888)	$ (208)

The movements in AOCI for Empire's pension and OPEB plans are reclassified to regulatory accounts since it is probable the unfunded amount of these plans will be afforded rate recovery (note 7(b)).

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

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

(b) Assumptions

Weighted average assumptions used to determine net benefit obligation for 2018 and 2017 were as follows:

	Pension benefits		OPEB	
	2018	2017	2018	2017
Discount rate	4.19%	3.43%	4.26%	3.60%
Interest crediting rate (for cash balance plans)	4.43%	4.50%	N/A	N/A
Rate of compensation increase	4.00%	3.00%	N/A	N/A
Health care cost trend rate				
Before age 65			6.25%	6.25%
Age 65 and after			6.25%	6.25%
Assumed ultimate medical inflation rate			4.75%	4.75%
Year in which ultimate rate is reached			2031	2024

The mortality assumption for December 31, 2018 was updated to the projected generationally scale MP-2018, adjusted to reflect the ultimate improvement rates in the 2018 Social Security Administration intermediate assumptions.

In selecting an assumed discount rate, the Company uses a modeling process that involves selecting a portfolio of high-quality corporate debt issuances (AA- or better) whose cash flows (via coupons or maturities) match the timing and amount of the Company's expected future benefit payments. The Company considers the results of this modeling process, as well as overall rates of return on high-quality corporate bonds and changes in such rates over time, to determine its assumed discount rate.

The rate of return assumptions are based on projected long-term market returns for the various asset classes in which the plans are invested, weighted by the target asset allocations.

Weighted average assumptions used to determine net benefit cost for 2018 and 2017 were as follows:

	Pension benefits		OPEB	
	2018	2017	2018	2017
Discount rate	3.57%	4.01%	3.60%	4.12%
Expected return on assets	7.13%	7.01%	6.52%	3.88%
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

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

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

(c) Benefit costs

The following table lists the components of net benefit cost 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	
	2018	2017	2018	2017
Service cost	$ 15,481	$ 14,747	$ 5,791	$ 4,838
Non-service costs				
Interest cost	18,717	20,191	6,727	6,642
Expected return on plan assets	(27,820)	(24,842)	(7,451)	(6,404)
Amortization of net actuarial loss (gain)	1,119	1,140	(272)	(230)
Amortization of prior service credits	(649)	(622)	(262)	(262)
Amortization of regulatory assets/ liability	9,823	13,031	3,982	391
Net benefit cost	$ 16,671	$ 23,645	$ 8,515	$ 4,975

As a result of the adoption of ASU 2017-07 (note 2(a)), the service cost components of pension plans and OPEB are shown as part of operating expenses within operating income in the consolidated statements of operations. The remaining components of net benefit cost are considered non-service costs and have been included outside of operating income in pension and post-employment non-service costs in the consolidated statements of operations. The Company applied the practical expedient for retrospective application on the consolidated statements of operations and as such, the $9,035 of non-service costs for the twelve months ended December 31, 2017 has been reclassified from administrative expenses to pension and post-employment non-service costs.

(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	69%	49% - 78%
Debt securities	31%	22% - 51%
	100%	

The fair values of investments as of December 31, 2018, by asset category, are as follows:

Asset Class	Level 1	Percentage
Equity securities	$ 338,946	75%
Debt securities	115,695	25%
Other	—	—%
	$ 454,641	100%

As of December 31, 2018, the funds do not hold any material investments in APUC.

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

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

(e) Cash flows

The Company expects to contribute $20,137 to its pension plans and $5,562 to its post-employment benefit plans in 2019.

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

	2019	2020	2021	2022	2023	2024—2028
Pension plan	$ 31,101	$ 29,366	$ 32,508	$ 33,415	$ 35,111	$ 183,338
OPEB	6,077	6,686	7,172	7,731	8,241	47,119

11. Other assets

Other assets consist of the following:

	2018	2017
Income tax recoverable	$ 1,961	$ 5,967
Deferred financing costs	4,449	3,546
Restricted cash	18,954	15,939
Other	9,335	10,811
	34,699	36,263
Less: current portion	(6,115)	(7,110)
	$ 28,584	$ 29,153

12. Other long-term liabilities

Other long-term liabilities consist of the following:

	2018	2017
Advances in aid of construction (a)	$ 63,703	$ 62,683
Environmental remediation obligation (b)	55,621	54,322
Asset retirement obligations (c)	43,291	44,166
Customer deposits (d)	29,974	28,529
Unamortized investment tax credits (e)	17,491	17,839
Deferred credits (f)	42,711	21,168
Preferred shares, Series C (g)	13,418	14,718
Other (h)	39,710	45,434
	305,919	288,859
Less: current portion	(42,337)	(46,754)
	$ 263,582	$ 242,105

(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 2018, $3,687 (2017 - $10,498) was transferred from advances in aid of construction to contributions in aid of construction.

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

12. Other long-term liabilities (continued)

(b) Environmental remediation obligation

A number of the Company's regulated utilities were named as potentially responsible parties for remediation of several sites at which hazardous waste is alleged to have been disposed as a result of historical operations of Manufactured Gas Plants ("MGP") and related facilities. The Company is currently investigating and remediating, as necessary, those MGP and related sites in accordance with plans submitted to the agency with authority for each of the respective sites.

The Company estimates the remaining undiscounted, unescalated cost of these MGP-related environmental cleanup activities will be $59,181 (2017 - $57,292) which at discount rates ranging from 2.5% to 2.8% represents the recorded accrual of $55,621 as of December 31, 2018 (2017 - $54,322). Approximately $36,611 is expected to be incurred over the next four years with the balance of cash flows to be incurred over the following 27 years.

Changes in the environmental remediation obligation are as follows:

	2018	2017
Opening balance	$ 54,322	$ 47,202
Remediation activities	(2,163)	(1,561)
Accretion	1,479	1,114
Changes in cash flow estimates	4,051	1,645
Revision in assumptions	(2,068)	5,922
Closing balance	$ 55,621	$ 54,322

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, 2018, the Company has reflected a regulatory asset of $82,295 (2017 - $82,711) for the MGP and related sites (note 7(a)).

(c) Asset retirement obligations

Asset retirement obligations mainly relate to legal requirements to: (i) remove wind farm facilities upon termination of land leases; (ii) cut (disconnect from the distribution system), purge (cleanup of natural gas and Polychlorinated Biphenyls "PCB" contaminants) and cap gas mains within the gas distribution and transmission system when mains are retired in place, or sections of gas main are removed from the pipeline system; (iii) clean and remove storage tanks containing waste oil and other waste contaminants; (iv) remove certain river water intake structures and equipment; (v) disposal of coal combustion residuals and PCB contaminants and (vi) remove asbestos upon major renovation or demolition of structures and facilities.

Changes in the asset retirement obligations are as follows:

	2018	2017
Opening Balance	$ 44,166	$ 18,486
Obligation assumed from business acquisition and constructed projects	225	28,267
Retirement activities	(5,130)	(2,811)
Accretion	1,974	1,981
Change in cash flow estimates	2,056	(1,757)
Closing Balance	$ 43,291	$ 44,166

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

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

12. Other long-term liabilities (continued)

(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

During the year, the Company settled $16,000 of contingent consideration related to prior acquisitions resulting in a gain of approximately $12,000 which was recorded as a reduction of acquisition costs on the consolidated statements of operations.

(g) Preferred Shares, Series C

APUC has 100 redeemable Series C preferred shares issued and outstanding. Thirty-six of the Series C preferred shares are owned by related parties controlled by executives of the Company. The preferred shares are mandatorily redeemable in 2031 for C$53,400 per share (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 C$53,400 per share.

As these shares are mandatorily redeemable for cash, they are classified as liabilities in the consolidated financial statements. The Series C preferred shares are accounted for under the effective interest method, resulting in accretion of interest expense over the term of the shares. Dividend payments are recorded as a reduction of the Series C preferred share carrying value.

Estimated dividend payments due in the next five years and dividend and redemption payments thereafter are as follows:

2019	$ 940
2020	985
2021	1,000
2022	1,019
2023	1,183
Thereafter to 2031	10,370
Redemption amount	3,914
	19,411
Less: amounts representing interest	(5,993)
	13,418
Less current portion	(940)
	$ 12,478

(h) Other

Convertible debentures

As at December 31, 2018, the carrying value of the convertible debentures was $470 (2017 - $971).

On March 1, 2016, the Company completed the sale of C$1,150,000 aggregate principal amount of 5.0% convertible debentures. The proceeds received from the initial instalment in 2016 and the final instalment in 2017, net of financing costs were $266,889 and $571,642, respectively.

The convertible debentures mature on March 31, 2026 and bore interest at an annual rate of 5% per C $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, 2018 is $nil (2017 - $7,193).

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

12. Other long-term liabilities (continued)

(h) Other (continued)

Convertible debentures (continued)

The debentures are convertible into up to 108,490,566 common shares. During the year ended December 31, 2018 $447 (2017 - $855,691) of principal converted to 56,926 (2017 - 108,370,081) common shares of the Company (note 13), representing conversion into common shares of 99.9% of the convertible debentures as at December 31, 2018.

13. Shareholders' capital

(a) Common shares

Number of common shares

	2018	2017
Common shares, beginning of year	431,765,935	274,087,018
Public offering (a)(i)	50,041,624	43,470,000
Conversion of convertible debentures (note 12(h))	56,926	108,370,081
Dividend reinvestment plan (a)(ii)	5,880,843	3,905,848
Exercise of share-based awards (c)	1,106,105	1,932,988
Common shares, end of year	488,851,433	431,765,935

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 December 20, 2018, APUC issued 12,536,350 common shares at $10.09 (C$13.76) per share pursuant to a public offering for proceeds of $126,485 (C$172,500) before issuance costs of $366 (C$492).

On April 24, 2018, APUC issued 37,505,274 common shares at $9.23 (C$11.85) per share pursuant to a public offering for gross proceeds of $346,458 (C$444,437) before issuance costs of $590 (C$765).

On November 10, 2017, APUC issued 43,470,000 common shares at $10.45 (C$13.25) per share pursuant to a public offering for proceeds of $454,158 (C$576,000) before issuance costs of $19,193 (C$24,342) or $14,109 (C$17,895) net of taxes.

(ii) 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 1,606,001 common shares under the dividend reinvestment plan.

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

13. Shareholders' capital (continued)

(b) Preferred shares

APUC is authorized to issue an unlimited number of preferred shares, issuable in one or more series, containing terms and conditions as approved by the Board.

The Company has the following Series A and Series D preferred shares issued and outstanding as at December 31, 2018 and 2017:

Preferred shares	Number of shares	Price per share	Carrying amount C$	Carrying amount $
Series A	4,800,000	C$ 25	C$116,546	$100,463
Series D	4,000,000	C$ 25	C$ 97,259	$ 83,836
				$184,299

The holders of Series A preferred shares are entitled to receive quarterly fixed cumulative preferential cash dividends, if, as and when declared by the Board. The dividend for each year up to, but excluding December 31, 2018 was an annual amount of C$1.125 per share. The dividend rate for the five-year period from and including December 31, 2018 to but excluding December 31, 2023 will be $1.2905. The Series A dividend rate will reset on December 31, 2023 and every five years thereafter at a rate equal to the then five-year Government of Canada bond yield plus 2.94%. The Series A preferred shares are redeemable at C$25 per share at the option of the Company on December 31, 2023 and every fifth year thereafter.

The holders of Series D preferred shares are entitled to receive fixed cumulative preferential dividends as and when declared by the Board at an annual amount of C$1.25 per share for each year up to, but excluding March 31, 2019. The Series D dividend rate will reset on that date and every five years thereafter at a rate equal to the then five-year Government of Canada bond yield plus 3.28%. The Series D preferred shares are redeemable at C$25 per share at the option of the Company on March 31, 2019 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 A did not convert to Series B on December 31, 2018. 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, 2023 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 12(g)).

(c) Share-based compensation

For the year ended December 31, 2018, APUC recorded $9,458 (2017 - $8,361) in total share-based compensation expense detailed as follows:

	2018	2017
Share options	$ 2,054	$ 3,070
Director deferred share units	714	593
Employee share purchase	312	436
Performance and restricted share units	6,378	4,262
Total share-based compensation	$ 9,458	$ 8,361

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

13. Shareholders' capital (continued)

(c) Share-based compensation (continued)

The compensation expense is recorded as part of administrative expenses in the consolidated statements of operations. The portion of share-based compensation costs capitalized as cost of construction is insignificant.

As of December 31, 2018, total unrecognized compensation costs related to non-vested options and PSUs were $1,221 and $8,243, respectively, and are expected to be recognized over a period of 1.64 and 1.60 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.

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

	2018	2017
Risk-free interest rate	2.1%	1.4%
Expected volatility	21%	25%
Expected dividend yield	4.8%	4.3%
Expected life	5.50 years	5.50 years
Weighted average grant date fair value per option	C$ 1.41	C$ 1.45

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

13. Shareholders' capital (continued)

(c) Share-based compensation (continued)

(i) Share option plan (continued)

Share option activity during the years is as follows:

	Number of awards		Weighted average exercise price	Weighted average remaining contractual term (years)		Aggregate intrinsic value
Balance, January 1, 2017	6,045,014	C$	9.64	6.27	C$	10,595
Granted	2,328,343		12.82	8.00		—
Exercised	(1,634,501)		7.81	3.76		7,696
Balance, December 31, 2017	6,738,856	C$	11.18	6.32	C$	19,380
Granted	1,166,717		12.80	8.00		—
Exercised	(1,589,211)		10.66	5.02		5,059
Forfeited	(23,720)		12.80	—		—
Balance, December 31, 2018	6,292,642	C$	11.61	5.75	C$	13,342
Exercisable, December 31, 2018	3,198,175	C$	10.44	4.93	C$	10,501

(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 dollars 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, 2018, a total of 252,698 common shares (2017 - 283,523) were issued to employees under the ESPP.

(iii) Director's deferred share units

Under the Company's Deferred Share Unit Plan, non-employee directors of the Company may elect annually to receive all or any portion of their compensation in DSUs in lieu of cash compensation. Directors' fees are paid on a quarterly basis and at the time of each payment of fees, the applicable amount is converted to DSUs. A DSU has a value equal to one of the Company's common shares. Dividends accumulate in the DSU account and are converted to DSUs based on the market value of the shares on that date. DSUs cannot be redeemed until the director retires, resigns, or otherwise leaves the Board. The DSUs provide for settlement in cash or shares at the election of the Company. As the Company does not expect to settle these instruments in cash, these options are accounted for as equity awards. As of December 31, 2018, 380,656 (2017 - 293,906) DSUs were outstanding pursuant to the election of the directors to defer a percentage of their director's fee in the form of DSUs. The aggregate number of common shares reserved for issuance from treasury by APUC under the DSU plan shall not exceed 1,000,000 common shares.

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

13. Shareholders' capital (continued)

(c) Share-based compensation (continued)

(iv) Performance and restricted share units

The Company offers a PSU and RSU plan to its employees as part of the Company's long-term incentive program. PSUs 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. RSU vesting conditions and dates vary by grant and are outlined in each award letter. RSUs are not subject to performance criteria. Dividends accumulating during the vesting period are converted to PSUs and RSUs based on the market value of the shares on that date and are recorded in equity as the dividends are declared. None of these PSUs or RSUs have voting rights. Any PSUs or RSUs not vested at the end of a performance period will expire. The PSUs 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 and RSU Plan shall not exceed 7,000,000 common shares.

Compensation expense associated with PSUs is recognized rateably over the performance period. Achievement of the performance criteria is estimated at the consolidated balance sheet dates. Compensation cost recognized is adjusted to reflect the performance conditions estimated to-date.

A summary of the PSUs and RSUs follows:

	Number of awards	Weighted average grant-date fair value	Weighted average remaining contractual term (years)	Aggregate intrinsic value
Balance, January 1, 2017	578,988	C$ 9.82	1.74	C$ 6,595
Granted, including dividends	811,974	13.54	2.00	—
Exercised	(374,973)	8.33	—	4,394
Forfeited	(60,961)	12.61	—	—
Balance, December 31, 2017	955,028	C$ 12.30	1.84	C$ 13,428
Granted, including dividends	791,524	12.41	2.00	—
Exercised	(285,551)	10.02	—	3,691
Forfeited	(68,869)	13.02	—	—
Balance, December 31, 2018	1,392,132	C$ 12.75	1.60	C$ 19,114
Exercisable, December 31, 2018	173,533	C$ 11.66	—	C$ 2,383

(v) Bonus deferral RSUs

During the year, the Company introduced a new bonus deferral RSU program to certain of its employees. Eligible employees have the option to receive a portion or all of their annual bonus payment in RSUs in lieu of cash. The RSUs provide for settlement in shares, and therefore these options are accounted for as equity awards. The RSUs granted are 100% vested and therefore, compensation expense associated with RSUs is recognized immediately upon issuance.

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

13. Shareholders' capital (continued)

(c) Share-based compensation (continued)

(iv) Bonus deferral RSUs

A summary of the bonus deferral RSUs follows:

	Number of awards	Weighted average grant-date fair value	Aggregate intrinsic value
Balance, December 31, 2017	—	C$ —	$ —
Granted, including dividends	131,611	12.82	—
Exercised	(4,545)	12.82	61
Balance and exercisable, December 31, 2018	127,066	C$ 12.82	C$ 1,745

14. Accumulated Other comprehensive income (loss)

AOCI consists of the following balances, net of tax:

	Foreign currency cumulative translation	Unrealized gain on cash flow hedges	Net change on available-for-sale investments	Pension and post-employment actuarial changes	Total
Balance, January 1, 2017	$ (25,921)	$ 53,740	$ 65	$ (10,833)	$ 17,051
OCI (loss) before reclassifications	(21,780)	8,004	—	600	(13,176)
Amounts reclassified	—	(6,378)	(65)	(224)	(6,667)
Net current period OCI	(21,780)	1,626	(65)	376	(19,843)
Balance, December 31, 2017	$ (47,701)	$ 55,366	$ —	$ (10,457)	$ (2,792)
Cumulative catch-up adjustment related to adoption of ASU 2018-02 on tax effects in AOCI (note 2(a))	—	11,657	—	(1,032)	10,625
OCI before reclassifications	(26,488)	1,567	—	2,046	(22,875)
Amounts reclassified	—	(4,257)	—	(86)	(4,343)
Net current period OCI	$ (26,488)	$ (2,690)	$ —	$ 1,960	$ (27,218)
Balance, December 31, 2018	$ (74,189)	$ 64,333	$ —	$ (9,529)	$ (19,385)

Amounts reclassified from AOCI for unrealized gain (loss) on cash flow hedges affected revenue from non-regulated energy sales while those for pension and post-employment actuarial changes affected pension and post-employment non-service costs.

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

15. Dividends

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

	2018		2017	
	Dividend	Dividend per share	Dividend	Dividend per share
Common shares	$ 235,440	$ 0.5011	$ 185,915	$ 0.4660
Series A preferred shares	C$ 5,400	C$ 1.1250	C$ 5,400	C$ 1.1250
Series D preferred shares	C$ 5,000	C$ 1.2500	C$ 5,000	C$ 1.2500

16. Related party transactions

Equity-method investments

The Company entered in a number of transactions with equity-method investees in 2018 and 2017 (note 8). In addition, the Company provides administrative and development services to its equity-method investees and is reimbursed for incurred costs. To that effect, the Company charged its equity-method investees $11,390 (2017 - $4,675) during the year.

Subject to certain limitations, Atlantica has a right of first offer on any proposed sale, transfer or other disposition by the AAGES entities (other than to APUC) of its interest in infrastructure facilities that are developed or constructed in whole or in part by the AAGES entities under long-term revenue agreements. Similarly, Atlantica has rights, subject to certain limitations, with respect to any proposed sale, transfer or other disposition of APUC's interest, not held through the AAGES entities, in infrastructure facilities that are developed or constructed in whole or in part by APUC outside of Canada or the United States under long-term revenue agreements. There were no such transactions in 2018.

Redeemable non-controlling interests

In 2018, contributions of $305,000 were received from AAGES B.V for a preference share of AY Holdings (note 8(a) and note 17).

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.

17. Non-controlling interests and redeemable non-controlling interests

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

	2018	2017
HLBV and other adjustments attributable to:		
Non-controlling interests - Class A partnership units	$ 103,150	$ 39,850
Non-controlling interests - redeemable Class A partnership units	7,545	10,358
Other net earnings attributable to:		
Non-controlling interests	(2,174)	(2,438)
	$ 108,521	$ 47,770
Redeemable non-controlling interests, held by related party	(2,622)	—
Net effect of non-controlling interests	$ 105,899	$ 47,770

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

17. Non-controlling interests and redeemable non-controlling interests (continued)

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 included in the Tax Act effective January 1, 2018 were reflected in the calculation of HLBV in 2018. The changes accelerated HLBV income from future years to the first quarter of 2018 in the amount of $55,900.

Non-controlling interests

As of December 31, 2018, non-controlling interests of $519,896 (2017 - $602,636) includes Class A partnership units held by tax equity investors in certain U.S. wind power and solar generating facilities of $519,100 (2017 - $601,780) and other non-controlling interests of $796 (2017 - $856). Contributions from Class A partnership investors of $15,250 and $42,750 was received for the Great Bay Solar Facility in 2018 and 2017, respectively (note 3(d)); $9,800 was received for the Bakersfield II Solar Facility on February 28, 2017 (note 3(g)); and, $166,595 was received for the Deerfield Wind Project on May 10, 2017 (note 8(f)(ii)).

Redeemable non-controlling interests

Non-controlling interests in subsidiaries that are redeemable upon the occurrence of uncertain events not solely within APUC's control are classified as temporary equity on the consolidated balance sheets. If the redemption is probable or currently redeemable, the Company records the instruments at their redemption value. Redemption is not considered probable as of December 31, 2018. Changes in redeemable non-controlling interests are as follows:

	Redeemable non-controlling interests held by related party		Redeemable non-controlling interests	
	2018	2017	2018	2017
Opening balance	$ —	$ —	$ 41,553	$ 21,922
Net effect from operations	2,622	—	(7,545)	(10,356)
Contributions, net of costs	305,000	—	—	31,105
Dividends and distributions declared	—	—	(644)	(1,118)
Closing balance	$ 307,622	$ —	$ 33,364	$ 41,553

Contributions of $305,000 were received from Abengoa-Algonquin Global Energy Solutions B.V. for a preference share of AY Holdings (note 8(a)). Contributions from Class A partnership investors of $31,212 were received for the Luning Solar Facility on February 17, 2017 (note 3(f)).

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

18. Income taxes

The provision for income taxes in the consolidated statements of operations represents an effective tax rate different than the Canadian enacted statutory rate of 26.5% (2017 - 26.5%). The differences are as follows:

		2018		2017
Expected income tax expense at Canadian statutory rate	$	35,102	$	46,410
Increase (decrease) resulting from:				
Effect of differences in tax rates on transactions in and within foreign jurisdictions and change in tax rates		(34,165)		(20,987)
Net loss from investment in Atlantica		25,870		—
Base Erosion Anti-Abuse Tax		6,101		—
Non-controlling interests share of income		29,637		18,979
Allowance for equity funds used during construction		(719)		(799)
Capital gain rate differential		722		(687)
Goodwill divestiture and permanent basis differences associated with Mountain Water condemnation		58		5,489
Non-deductible acquisition costs		4,267		13,660
Change in valuation allowance		1,160		(974)
Tax credits		(1,419)		(6,288)
Adjustment relating to prior periods		3,673		(31)
U.S. Tax reform and related deferred tax adjustments		(18,363)		17,112
Other		1,448		1,543
Income tax expense	$	53,372	$	73,427

On December 22, 2017, the Tax Act was signed into legislation. The Tax Act includes a broad range of legislative changes including a reduction of the U.S. 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 Tax 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.

As a result of the Tax Act being enacted during 2017, the Company was 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 recognized a provisional charge to income tax expense of $17,112 in 2017 as a result of the revaluation of its U.S. non-regulated net deferred income tax assets. In 2018, the Company completed its remeasurement of deferred income tax assets and liabilities as permitted under the measurement period outlined under SEC Staff Accounting Bulletin 118, *Income Tax Accounting Implications of the Tax Cuts and Jobs Act* ("SAB 118"). The final adjustments related to the implementation of U.S. Tax Reform resulted in a non-cash accounting benefit of $18,363 which was recorded in the Company's 2018 consolidated statement of operations.

On June 1, 2018, the State of Missouri enacted legislation that, effective for tax years beginning on or after January 1, 2020, reduces the corporate income tax rate from 6.25% to 4%, among other legislative changes. The Company reduced its regulated net deferred income tax liabilities by $15,586 and recorded an equivalent increase to net regulatory liabilities since the benefit of lower Missouri state income taxes is probable of being returned to customers by order of the applicable regulator.

For the years ended December 31, 2018 and 2017, earnings before income taxes consist of the following:

		2018		2017
Canada	$	(109,537)	$	(2,711)
U.S.		241,998		177,843
	$	132,461	$	175,132

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

18. Income taxes (continued)

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

	Current	Deferred	Total
Year ended December 31, 2018			
Canada	$ 2,872	$ (14,197)	$ (11,325)
United States	8,475	56,222	64,697
	$ 11,347	$ 42,025	$ 53,372
Year ended December 31, 2017			
Canada	$ 3,296	$ (14,168)	$ (10,872)
United States	4,221	80,078	84,299
	$ 7,517	$ 65,910	$ 73,427

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, 2018 and 2017 are presented below:

	2018	2017
Deferred tax assets:		
Non-capital loss, investment tax credits, currently non-deductible interest expenses, and financing costs	$ 329,099	$ 328,679
Pension and OPEB	48,586	43,638
Acquisition-related costs	1,420	1,601
Environmental obligation	14,790	14,803
Reserves and other non-deductible costs	20,517	30,652
Regulatory liabilities	161,560	154,597
Financial derivatives	12,831	7,607
Other	10,425	16,384
Total deferred income tax assets	599,228	597,961
Less valuation allowance	(28,018)	(19,951)
Total deferred tax assets	571,210	578,010
Deferred tax liabilities:		
Property, plant and equipment	(653,962)	(668,083)
Intangible assets	(7,247)	(7,157)
Outside basis in partnership	(167,659)	(125,519)
Regulatory accounts	(113,758)	(114,062)
Financial derivatives	—	(980)
Other	(314)	—
Total deferred tax liabilities	(942,940)	(915,801)
Net deferred tax liabilities	$ (371,730)	$ (337,791)
Consolidated Balance Sheets Classification:		
Deferred tax assets	$ 72,415	$ 61,357
Deferred tax liabilities	(444,145)	(399,148)
Net deferred tax liabilities	$ (371,730)	$ (337,791)

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

18. Income taxes (continued)

The valuation allowance for deferred tax assets as at December 31, 2018 was $28,018 (2017 - $19,951). 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, 2018, 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	$ 925,439

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 $280,643 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.

19. Basic and diluted net earnings per share

Basic and diluted earnings per share have been calculated on the basis of net earnings attributable to the common shareholders of the Company and the weighted average number of common shares and bonus deferral restricted share units outstanding. Diluted net earnings per share is computed using the weighted-average number of common shares, subscription receipts outstanding, additional shares issued subsequent to year-end under the dividend reinvestment plan, PSUs, RSUs and DSUs outstanding during the year and, if dilutive, potential incremental common shares resulting from the application of the treasury stock method to outstanding share options. The convertible debentures (note 12(h)) 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:

	2018	2017
Net earnings attributable to shareholders of APUC	$ 184,988	$ 149,475
Series A Preferred shares dividend	4,169	4,164
Series D Preferred shares dividend	3,858	3,856
Net earnings attributable to common shareholders of APUC from continuing operations – Basic and Diluted	$ 176,961	$ 141,455
Weighted average number of shares		
Basic	461,818,023	382,323,434
Effect of dilutive securities	4,227,595	3,662,714
Diluted	466,045,618	385,986,148

The shares potentially issuable as a result of 3,380,184 share options (2017 - 2,328,343) are excluded from this calculation as they are anti-dilutive.

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

20. Segmented information

The Company is managed 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 assets in North America and internationally; the Liberty Utilities Group owns and operates a portfolio of regulated electric, natural gas, water distribution and wastewater collection utility systems and transmission operations in the United States.

For purposes of evaluating divisional performance, the Company allocates the realized portion of any gains or losses on financial instruments to specific divisions. Dividend income from Atlantica (note 8(a)) and equity income from the AAGES entities (note 8(b)) are included in the operations of the Liberty Power Group. The change in value of the investment in Atlantica carried at fair value (note 8(a)) and unrealized portion of any gains or losses on derivative instruments not designated in a hedging relationship are not considered in management's evaluation of divisional performance and are therefore allocated and reported under corporate. The results of operations and assets for these segments are reflected in the tables below.

	Year ended December 31, 2018			
	Liberty Utilities Group	Liberty Power Group	Corporate	Total
Revenue [1][2]	$ 1,400,164	$ 247,223	$ —	$ 1,647,387
Fuel, power and water purchased	456,974	27,164	—	484,138
Net revenue	943,190	220,059	—	1,163,249
Operating expenses	401,486	70,980	—	472,466
Administrative expenses	33,234	18,539	937	52,710
Depreciation and amortization	177,719	82,044	1,009	260,772
Gain on foreign exchange	—	—	(58)	(58)
Operating income	330,751	48,496	(1,888)	377,359
Interest expense	99,063	50,920	2,135	152,118
Interest, dividend, equity and other income	(5,558)	(45,741)	(1,840)	(53,139)
Change in value of investment carried at fair value	—	—	137,957	137,957
Other expenses	5,699	1,576	687	7,962
Earnings (loss) before income taxes	$ 231,547	$ 41,741	$ (140,827)	$ 132,461
Property, plant and equipment	$ 4,210,115	$ 2,152,420	$ 31,023	$ 6,393,558
Investment carried at fair value	—	814,530	—	814,530
Equity-method investees	959	29,273	260	30,492
Total assets	6,012,641	3,269,786	106,541	9,388,968
Capital expenditures	370,221	96,148	—	466,369

(1) Revenue includes $14,953 related to net hedging gains from energy derivative contracts for the twelve months ended December 31, 2018 that do not represent revenue recognized from contracts with customers.

(2) Liberty Utilities Group revenue includes $7,425 related to alternative revenue programs for the twelve months ended December 31, 2018 that do not represent revenue recognized from contracts with customers.

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

20. Segmented information (continued)

	Year ended December 31, 2017			
	Liberty Utilities Group	Liberty Power Group	Corporate	Total
Revenue	$ 1,290,786	$ 231,152	$ —	$ 1,521,938
Fuel and power purchased	373,635	19,590	—	393,225
Net revenue	917,151	211,562	—	1,128,713
Operating expenses	383,380	66,851	—	450,231
Administrative expenses	33,037	15,992	611	49,640
Depreciation and amortization	171,111	79,183	1,020	251,314
Gain on foreign exchange	—	—	323	323
Operating income (loss)	329,623	49,536	(1,954)	377,205
Interest expense	97,698	36,646	21,478	155,822
Interest, dividend and other income	(4,208)	(2,871)	(2,159)	(9,238)
Other expense	6,087	1,713	47,689	55,489
Earnings (loss) before income taxes	$ 230,046	$ 14,048	$ (68,962)	$ 175,132
Property, plant and equipment	$ 4,023,479	$ 2,246,869	$ 34,549	$ 6,304,897
Equity-method investees	2,220	29,710	337	32,267
Total assets	5,817,599	2,474,293	103,675	8,395,567
Capital expenditures	407,408	157,695	—	565,103

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:

	2018	2017
Revenue		
Canada	$ 70,358	$ 73,406
United States	1,577,029	1,448,532
	$ 1,647,387	$ 1,521,938
Property, plant and equipment		
Canada	$ 415,979	$ 453,323
United States	5,977,579	5,851,574
	$ 6,393,558	$ 6,304,897
Intangible assets		
Canada	$ 23,994	$ 27,624
United States	31,000	23,479
	$ 54,994	$ 51,103

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

21. 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.

Claim by Gaia Power Inc.

On October 30, 2018, Gaia Power Inc. ("Gaia") commenced an action in the Ontario Superior Court of Justice against APUC and certain of its subsidiaries, claiming damages of not less than $345,000 and punitive damages in the sum of $25,000. The action arises from Gaia's 2010 sale, to a subsidiary of APUC, of Gaia's interest in certain proposed wind farm projects in Canada. Pursuant to a 2010 royalty agreement, Gaia is entitled to royalty payments if the projects are developed and achieve certain agreed targets. APUC believes that the claims are without merit, and intends to vigorously defend the action.

Condemnation Expropriation Proceedings

Liberty Utilities (Apple Valley Ranchos Water) Corp. is the subject of a condemnation lawsuit filed by the town of Apple Valley. A Court will determine the necessity of the taking by Apple Valley and, if established, a jury will determine the fair market value of the assets being condemned. Resolution of the condemnation proceedings is expected to take two to three years. Any taking by government entities would legally require fair compensation to be paid, however, there is no assurance that the value received as a result of the condemnation will be sufficient to recover the Company's net book value of the utility assets taken.

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 $88,600. Upon taking possession of Mountain Water's assets on June 22, 2017, the city of Missoula paid $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 contracts relating to the assets.

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

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

21. Commitments and contingencies (continued)

(b) Commitments

In addition to the commitments related to the proposed acquisitions and development projects disclosed in notes 3 and 8, the following significant commitments exist as of December 31, 2018.

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)	$ 46,536	$ 10,896	$ 11,114	$ 11,338	$ 11,566	$ 191,208	$ 282,658
Gas supply and service agreements (ii)	77,658	51,349	27,672	24,422	22,424	48,313	251,838
Service agreements	43,732	39,093	38,451	37,463	40,737	312,559	512,035
Capital projects	67,575	1,663	196	7,330	—	—	76,764
Operating leases	7,629	7,154	7,096	7,076	6,776	178,583	214,314
Total	$243,130	$110,155	$ 84,529	$ 87,629	$ 81,503	$ 730,663	$ 1,337,609

(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, 2018. 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.

22. Non-cash operating items

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

	2018	2017
Accounts receivable	$ 3,005	$ (45,818)
Fuel and natural gas in storage	1,351	(4,385)
Supplies and consumables inventory	(7,189)	(1,864)
Income taxes recoverable	(763)	(557)
Prepaid expenses	2,907	(2,755)
Accounts payable	(22,915)	7,525
Accrued liabilities	28,687	14,041
Current income tax liability	2,974	(3,190)
Asset retirements and environmental obligations	(7,293)	(4,372)
Net regulatory assets and liabilities	(8,890)	(46,344)
	$ (8,126)	$ (87,719)

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

23. Financial instruments

(a) Fair value of financial instruments

2018	Carrying amount	Fair value	Level 1	Level 2	Level 3
Notes receivable	$ 103,696	$ 110,019	$ —	$ 110,019	$ —
Investment in Atlantica	814,530	814,530	814,530	—	—
Derivative instruments [1]:					
Energy contracts designated as a cash flow hedge	61,838	61,838	—	—	61,838
Currency forward contract not designated as a hedge	869	869	—	869	—
Commodity contracts for regulated operations	101	101	—	101	—
Total derivative instruments	62,808	62,808	—	970	61,838
Total financial assets	$ 981,034	$ 987,357	$ 814,530	$ 110,989	$ 61,838
Long-term debt	$3,336,795	$3,356,773	$ 768,400	$2,588,373	$ —
Convertible debentures	470	639	639	—	—
Preferred shares, Series C	13,418	13,703	—	13,703	—
Derivative instruments:					
Energy contracts designated as a cash flow hedge	57	57	—	—	57
Cross-currency swap designated as a net investment hedge	93,198	93,198	—	93,198	—
Interest rate swap designated as a hedge	8,473	8,473	—	8,473	—
Commodity contracts for regulated operations	1,114	1,114	—	1,114	—
Total derivative instruments	102,842	102,842	—	102,785	57
Total financial liabilities	$3,453,525	$3,473,957	$ 769,039	$2,704,861	$ 57

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

23. Financial instruments (continued)

(a) Fair value of financial instruments (continued)

2017	Carrying amount	Fair value	Level 1	Level 2	Level 3
Notes receivable	$ 33,378	$ 38,192	$ —	$ 38,192	$ —
Derivative instruments [1]:					
Energy contracts designated as a cash flow hedge	63,363	63,363	—	—	63,363
Energy contracts not designated as a cash flow hedge	109	109	—	109	—
Commodity contracts for regulatory operations	74	74	—	74	—
Total derivative instruments	63,546	63,546	—	183	63,363
Total financial assets	$ 96,924	$ 101,738	$ —	$ 38,375	$ 63,363
Long-term debt	$3,079,551	$3,262,711	$ 651,969	$2,610,742	$ —
Convertible debentures	971	1,018	1,018	—	—
Preferred shares, Series C	14,718	15,124	—	15,124	—
Derivative instruments:					
Energy contracts designated as a cash flow hedge	77	77	—	—	77
Energy contracts not designated as a cash flow hedge	31	31	—	31	—
Cross-currency swap designated as a net investment hedge	57,412	57,412	—	57,412	—
Interest rate swaps designated as a hedge	8,460	8,460	—	8,460	—
Currency forward contract not designated as hedge	344	344	—	344	—
Commodity contracts for regulated operations	2,620	2,620	—	2,620	—
Total derivative instruments	68,944	68,944	—	68,867	77
Total financial liabilities	$3,164,184	$3,347,797	$ 652,987	$2,694,733	$ 77

(1) Balance of $441 associated with certain weather derivatives have been excluded, as they are accounted for based on intrinsic value rather than fair value.

The Company has determined that the carrying value of its short-term financial assets and liabilities approximates fair value as of December 31, 2018 and 2017 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 fair value of the investment in Atlantica (level 1) is measured at the closing price on the NASDAQ stock exchange.

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

23. Financial instruments (continued)

(a) Fair value of financial instruments (continued)

The Company’s level 1 fair value of long-term debt is measured at the closing price on the NYSE stock exchange and the Canadian over-the-counter closing price. The Company’s level 2 fair value of long-term debt at fixed interest rates and Series C preferred shares has been determined using a discounted cash flow method and current interest rates. The Company's level 2 fair value of convertible debentures has been determined as the greater of their face value and the quoted value of APUC's common shares on a converted basis.

The Company’s level 2 fair value derivative instruments primarily consist of swaps, options, rights and forward physical derivatives where market data for pricing inputs are observable. Level 2 pricing inputs are obtained from various market indices and utilize discounting based on quoted interest rate curves which are observable in the marketplace.

The Company’s level 3 instruments consist of energy contracts for electricity sales. The significant unobservable inputs used in the fair value measurement of energy contracts are the internally developed forward market prices ranging from $14.55 to $172.97 with a weighted average of $24.72 as of December 31, 2018. The weighted average forward market prices are developed based on the quantity of energy expected to be sold monthly and the expected forward price during that month. Significant increases (decreases) in any of these inputs in isolation would have resulted in a significantly lower (higher) fair value measurement. The change in the fair value of the energy contracts is detailed in notes 23(b)(ii) and 23(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.

(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:

	2018
Financial contracts: Swaps	2,366,386
Options	300,000
Forward contracts	6,560,000

The accounting for these derivative instruments is subject to guidance for rate regulated enterprises. Therefore, the fair value of these derivatives is recorded as current or long-term assets and liabilities, with offsetting positions recorded as regulatory assets and regulatory liabilities in the consolidated balance sheets. Most of the gains or losses on the settlement of these contracts are included in the calculation of the fuel and commodity costs adjustments (note 7(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.

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

23. Financial instruments (continued)

(b) Derivative instruments

(i) Commodity derivatives – regulated accounting (continued)

The following table presents the impact of the change in the fair value of the Company's natural gas derivative contracts had on the consolidated balance sheets:

	2018	2017
Regulatory assets:		
Swap contracts	$ 66	$ —
Forward contracts	$ —	$ 6,319
Regulatory liabilities:		
Swap contracts	$ 218	$ 287
Option contracts	$ 134	$ 138
Forward contracts	$ 1,259	$ —

(ii) Cash flow hedges

The Company reduces the price risk on the expected future sale of power generation at Sandy Ridge, Senate and Minonk Wind Facilities by entering into the following long-term energy derivative contracts.

Notional quantity (MW-hrs)	Expiry	Receive average prices (per MW-hr)	Pay floating price (per MW-hr)
871,391	December 2028	36.33	PJM Western HUB
2,438,697	December 2023	29.06	PJM NI HUB
2,997,939	December 2027	36.46	ERCOT North HUB

Subsequent to year-end, the Company entered into a long-term energy derivative contract for the Minonk Wind Facility with a notional quantity of 251,581 MW-hours and a price of $20.72 per MW-hr. The contract expires December 2024.

The Company was party to a 10-year forward-starting interest rate swap beginning on July 25, 2018 in order to reduce the interest rate risk related to the probable issuance on that date of a 10-year C$135,000 bond. During the year, the Company amended and extended the forward-starting date of the interest rate swap to begin on March 29, 2019. As a result of the amendment, $898 of hedge ineffectiveness was recognized in earnings upon hedge dedesignation. The change in fair value since the hedge redesignation date is recorded in OCI. Subsequent to year end, the Company settled the forward-starting interest rate swap contract as it issued C$300,000 10-year senior unsecured notes with an interest rate of 4.60% (note 9(g)).

In 2017, the Company settled forward contracts to purchase $250,000 10-year U.S. Treasury bills at an interest rate of 1.8395% and $250,000 30-year U.S. Treasury bills at an interest rate of 2.5539% designated as hedges to the interest rate risk related to $479,000 of senior unsecured notes. The effective portion of the hedge was recorded in OCI at the time and is reclassified to interest expense as the underlying hedged transactions are incurred.

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

23. 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:

	2018	2017
Effective portion of cash flow hedge	$ 1,567	$ 8,004
Amortization of cash flow hedge	(33)	(27)
Amounts reclassified from AOCI	(4,224)	(6,351)
OCI attributable to shareholders of APUC	$ (2,690)	$ 1,626

The Company expects $6,289 and $989 of unrealized gains currently in AOCI to be reclassified, net of taxes into non-regulated energy sales and interest expense, respectively, within the next twelve months, as the underlying hedged transactions settle.

(iii) Foreign exchange hedge of net investment in foreign operation

The Company is exposed to currency fluctuations from its Canadian based operations. APUC manages this risk primarily through the use of natural hedges by using Canadian long-term debt to finance its Canadian operations and a combination of foreign exchange forward contracts and spot purchases. APUC only enters into foreign exchange forward contracts with major North American financial institutions having a credit rating of A or better, thus reducing credit risk on these forward contracts.

The Company's Canadian operations are determined to have the Canadian dollar as their functional currency and are exposed to currency fluctuations from their U.S. dollar transactions. The Company designates the amounts drawn on its revolving and bank credit facilities denominated in U.S. dollars as a hedge of the foreign currency exposure of its net investment in its U.S. investments and subsidiaries. The related foreign currency transaction gain or loss designated as, and effective as, a hedge of the net investment in a foreign operation are reported in the same manner as the translation adjustment (in OCI) related to the net investment. A foreign currency loss of $37,204 for the year ended December 31, 2018 (2017 - gain of $17,817) was recorded in OCI.

Concurrent with its C$150,000, C$200,000 and C$300,000 debenture offerings in December 2012, January 2014, and January 2017, respectively, the Company entered into cross currency swaps, coterminous with the debentures, to effectively convert the Canadian dollar denominated offering into U.S. dollars. The Company designated the entire notional amount of the cross currency fixed-for-fixed interest rate swap and related short-term U.S. dollar payables created by the monthly accruals of the swap settlement as a hedge of the foreign currency exposure of its net investment in the 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 loss of $41,244 (2017 - gain of $19,063) was recorded in OCI in 2018.

(iv) Other derivatives

The Company provides energy requirements to various customers under contracts at fixed rates. While the production from the Tinker Hydroelectric Facility is expected to provide a portion of the energy required to service these customers, APUC anticipates having to purchase a portion of its energy requirements at the ISO NE spot rates to supplement self-generated energy.

This risk is mitigated through the use of short-term financial forward energy purchase contracts that are classified as derivative instruments. The electricity derivative contracts are net settled fixed-for-floating swaps whereby APUC pays a fixed price and receives the floating or indexed price on a notional quantity of energy over the remainder of the contract term at an average rate, as per the following table. These contracts are not accounted for as hedges and changes in fair value are recorded in earnings as they occur.

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

23. 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 23(b)(ii)).

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, 2018, a loss on foreign exchange gain of $1,115 (2017 - loss of $297) 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:

	2018	2017
Change in unrealized loss (gain) on derivative financial instruments:		
Energy derivative contracts	$ 77	$ (79)
Currency forward contract	(1,230)	297
Commodity contracts	—	(2,885)
Total change in unrealized gain on derivative financial instruments	$ (1,153)	$ (2,667)
Realized loss (gain) on derivative financial instruments:		
Interest rate swaps	—	(144)
Energy derivative contracts	(73)	553
Currency forward contract	115	12,261
Total realized loss on derivative financial instruments	$ 42	$ 12,670
Loss (gain) on derivative financial instruments not accounted for as hedges	(1,111)	10,003
Ineffective portion of derivative financial instruments accounted for as hedges	632	637
	$ (479)	$ 10,640
Amounts recognized in the consolidated statements of operations consist of:		
Loss (gain) on derivative financial instruments	636	(1,918)
Loss (gain) on foreign exchange	(1,115)	12,558
	$ (479)	$ 10,640

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

23. 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 84% of revenue from power generation is earned from large utility customers having a credit rating of Baa2 or better by Moody's, or BBB or higher by S&P, or BBB or higher by DBRS. Revenue is generally invoiced and collected within 45 days.

The remaining revenue is primarily earned by the 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 $207,740 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, 2018, the Company's maximum exposure to credit risk for these financial instruments was as follows:

	December 31, 2018	
	Canadian $	US $
Cash and cash equivalents and restricted cash	$ 27,720	$ 45,452
Accounts receivable	13,562	241,068
Allowance for doubtful accounts	—	(5,281)
Notes receivable	138,353	2,279
	$ 179,635	$ 283,518

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, 2018, in addition to cash on hand of $46,819 the Company had $1,046,826 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.

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

23. 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	$ 334,855	$ 420,797	$ 825,596	$1,740,471	$3,321,719
Convertible debentures	—	—	—	470	470
Advances in aid of construction	1,205	—	—	62,498	63,703
Interest on long-term debt	156,768	269,942	221,528	928,736	1,576,974
Purchase obligations	325,326	—	—	—	325,326
Environmental obligation	4,158	30,140	2,885	21,998	59,181
Derivative financial instruments:					
Cross-currency swap	5,277	46,026	34,436	7,459	93,198
Interest rate swaps	8,473	—	—	—	8,473
Currency forward	—	—	—	—	—
Energy derivative and commodity contracts	588	526	57	—	1,171
Other obligations	33,350	—	—	122,408	155,758
Total obligations	$ 870,000	$ 767,431	$1,084,502	$2,884,040	$5,605,973

24. Comparative figures

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

Notes

Notes

CORPORATE INFORMATION

DIRECTORS
Kenneth Moore – Chair of the Board – Managing Partner, NewPoint Capital Partners Inc.
Chris Jarratt – Vice Chair, Algonquin Power & Utilities Corp.
Ian Robertson – Chief Executive Officer, Algonquin Power & Utilities Corp.
Christopher Ball – Executive Vice President, Corpfinance International Ltd.
D. Randy Laney – Former Chairman of the Board, The Empire District Electric Company
Masheed Saidi – Former Executive VP and Chief Operating Officer, U.S. Transmission, National Grid USA
Dilek Samil – Former Executive VP and Chief Operating Officer, NV Energy
Melissa Stapleton Barnes – Senior VP, Enterprise Risk Management, and Chief Ethics and Compliance Officer, Eli Lilly and Company
George Steeves – Principal, True North Energy

THE MANAGEMENT GROUP
Ian Robertson – Chief Executive Officer
Chris Jarratt – Vice Chair
David Bronicheski – Chief Financial Officer
Johnny Johnston – Chief Operating Officer
Jeff Norman – Chief Development Officer
Mary Ellen Paravalos – Chief Compliance and Risk Officer
David Pasieka – Chief Transformation Officer
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The New York Stock Exchange: AQN, AQNA

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