Algonquin Power & Utilities Corp.

ANNUAL REPORT 2017

BUILDING A STRONG FOUNDATION FROM WHICH TO DELIVER SHAREHOLDER VALUE

Algonquin Power & Utilities Corp. ("APUC") owns and operates a diversified portfolio of regulated and non-regulated generation, distribution, and transmission utility assets with a total value exceeding $10 billion.

APUC's operations are organized across two primary North American business units.

- **Liberty Power** owns and operates a diversified portfolio of non-regulated renewable and thermal electric generation assets with a total capacity of approximately 1,545 MW.

- **Liberty Utilities** owns and operates a portfolio of U.S. - based regulated electric, natural gas, water distribution and wastewater collection utility systems, and transmission operations which collectively serve the needs of approximately 762,000 customers.

APUC is also **active in International Infrastructure Development and Operations** through its newly-formed joint venture - Abengoa Algonquin Global Energy Solutions (AAGES) and its 25% equity interest in Atlantica Yield plc (NASDAQ:AY).

APUC has developed an unparalleled portfolio of conservative building blocks with which to grow its earnings and cash flows and support share price appreciation and a growing dividend.

ALGONQUIN
Power & Utilities Corp.

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

Cover image: Liberty Utilities' 50 MW Luning Facility, commissioned in Q1 2017

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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; 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 and analysis section of this Annual Report beginning at page 1.

LIBERTY UTILITIES

Transformational Growth in 2017

APUC's Liberty Utilities business group is its rate-regulated generation, transmission and distribution utility which provides electricity, natural gas, and water utility services to a total of approximately 762,000 customers in 12 U.S. states. APUC experienced transformational growth across it utility operating modalities in 2017, much of which can be attributed to the acquisition of The Empire District Electric Company ("Empire"). Marking a first for APUC, our utility rate base now includes power generating capacity. A total of nine power generating facilities were added to Liberty Utilities' portfolio of rate-based assets in 2017, including approximately 1,400 MW of generating capacity sourced from the Empire acquisition and another 50 MW of newly-commissioned solar generating capacity within Liberty Utilities' western region.

Liberty Utilities is committed to reducing customer costs through increased efficiencies and a prudent increase in the amount of renewable energy within the electricity mix delivered to customers. The expanded transmission businesses now include 1,200 miles of electrical transmission lines and 100 miles of natural gas transmission pipelines. Liberty Utilities is focused on delivering increased efficiencies to customers through continued investment in its utility systems.

APUC seeks to maximize total shareholder value through growth in earnings and cash flows to support share price appreciation and a growing dividend.

Total Customers (Total Connections)	2017	2016	Y/Y Growth
Electricity	265,000	94,000	182%
Natural Gas	337,000	293,000	15%
Water and Wastewater[1]	160,000	178,000	-10%
Total	**762,000**	**565,000**	**35%**

[1] Reduction reflects the disposition of Mountain Water Company in 2017.

UTILITY GROWTH CONTINUES

Seamless Integration, Strong Performance

On January 1, 2017, APUC completed the acquisition of Empire, a rate-regulated water, gas and electric utility serving approximately 221,000 customers in Missouri, Arkansas, Oklahoma, and Kansas. APUC's core utility operations have expanded materially - today, approximately 1,850 Liberty Utilities employees are dedicated to reliably meeting the needs of our electricity, natural gas, and water utility customers in 12 U.S. states. We were pleased that the integration of Empire's employees and operations was highly successful, and that Empire's contributions to our financial results were aligned with our expectations.

LIBERTY POWER

APUC is dedicated to maintaining strong access to the capital necessary to build its business. In 2017, APUC successfully raised a combined total of approximately $2.5 billion to fund its strategic growth initiatives.

2017 Strength and Stability

APUC's Liberty Power business group generates and sells electricity produced by its diversified portfolio of North American renewable and clean power generation facilities. Liberty Power's portfolio of non-regulated generation facilities includes approximately 1,545 MW of hydroelectric, wind, solar, and thermal generating capacity, delivering renewable and clean energy under long term off-take agreements. Active across six Canadian provinces and eight U.S. states, Liberty Power delivers increasing shareholder value through the development of new greenfield power generation projects and the efficient operation of its extensive fleet of operational power facilities.

During 2017, our power development team successfully added a total of 160 MW of new renewable energy capacity to our portfolio, including our 150 MW Deerfield Wind Facility in Michigan and our 10 MW Bakersfield II Solar Facility in California.

INTERNATIONAL DEVELOPMENT PLATFORM

On November 1, 2017, APUC announced that it had entered into agreements to create a new joint venture, Abengoa Algonquin Global Energy Solutions ("AAGES"), and to concurrently purchase a 25% equity interest in Atlantica Yield plc ("Atlantica" – NASDAQ:AY). Collectively these transactions represent APUC's important first steps into the international infrastructure development arena. We announced the successful completion of these transactions on March 9, 2018.

Accessing New International Infrastructure Opportunities through AAGES

AAGES provides a unique and risk-managed opportunity for APUC to pursue international infrastructure development while working alongside a proven, experienced partner. APUC has gained access to a curated collection of international development opportunities. Our partner in the joint venture, Seville, Spain-based Abengoa, S.A. ("Abengoa") has a 70-year track record of providing engineering and construction activities to a global client base. AAGES represents an important new component of our growth strategy, one which we believe will create enduring long-term value for our shareholders.

Atlantica Investment - Diverse, High Quality Portfolio

Atlantica owns and operates a diverse, long-term contracted portfolio of 22 facilities representing 1.7 GW of clean power generating capacity, 1,770 kilometers of electric transmission lines, and two desalination plants in selected global markets including North America, South America and EMEA. Atlantica's portfolio is complementary to APUC's existing operations, and APUC's commitment to Atlantica is expected to strengthen Atlantica's prospects through the addition of new assets, thereby accelerating the growth of its cash available for distribution.

Concentrating Solar facility. Photo courtesy of Atlantica.

2017 FINANCIAL ACHIEVEMENTS

APUC is led by an experienced executive management team that has a long-term track record of successfully growing the business. In 2017, APUC achieved:

85% Growth in adjusted EBITDA

81% Growth in adjusted net earnings

72% Growth in adjusted funds from operations

11% Increase in dividend per share

30% Increase in adjusted net earnings per share

26% Annual total shareholder return

2017 FINANCIAL HIGHLIGHTS

(in C$ millions)

Revenue	2017	2016	2015
Generation Revenue	282.6	243.1	222.6
Distribution Revenue	1,664.3	815.5	766.3
Other	30.9	37.4	39.0
Total Revenue	**1,977.8**	**1,096.0**	**1,027.9**
Adjusted EBITDA[1]	**883.4**	**476.9**	**375.4**
Earnings, Funds from Operations and Dividends			
Adjusted Funds from Operations[1]	614.5	356.4	287.4
Adjusted Net Earnings[1]	292.1	161.6	121.5
Per Share	0.74	0.57	0.46
Dividends to Shareholders	242.5	149.2	124.8
Per Share	0.61	0.55	0.49
Balance Sheet Data			
Total Assets	10,533.6	8,249.5	4,991.7
Long Term Debt (incl. current portion & convertible debentures)	3,864.5	4,272.0	1,486.8
Number of Shares outstanding as of Dec. 31	431,765,935	274,087,018	255,869,419
Renewable energy production (% of long term average)	**98%**	**94%**	**93%**
Utility Connections	**762,000**	**565,00**	**489,000**

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

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 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 further discussion, calculation and analysis of these Financial Measures can be found in the Management Discussion & Analysis section of this Annual Report.

OUR COMMITMENT TO ENTERPRISE RISK MANAGEMENT AND SUSTAINABILITY

Effective Risk Management – A Key to our Success

We are committed to continuous improvement of our risk management systems to address the changing dynamics of our business and our markets. In 2017, a new Risk Committee within our Board of Directors was established to provide additional oversight to our Enterprise Risk Management program. APUC-wide training remains an important means through which to ensure risks continue to be identified, analyzed and mitigated to optimize the likelihood of favorable business outcomes.

Safety is Embedded in our Culture

Safety remains a core component of APUC's culture, and we continue to refine the systems and programs that ensure the safety of our employees, our customers, and the communities in which we operate. APUC's enduring safety commitment is embodied in its "Drive to Zero" program and its goal to operate the businesses with zero lost time injuries and illnesses. APUC is reaping the tangible benefits of our commitment to safety across the organization – a prime example is the achievement of zero lost time injuries within the Liberty Power business group since 2015.

Dedication to Sustainable Practices

APUC continued to promote responsible and sustainable business practices throughout our operations in 2017. To strengthen our environmental measurement and management practices, APUC's environmental team commenced the implementation of an enterprise-wide Environmental Management System which will serve as the cornerstone of our efforts to achieve industry-leading environmental performance and management. 2017 also marked APUC's 10th consecutive year of reporting under the Carbon Disclosure Project.

AQN BY THE NUMBERS

25 PROVINCES AND STATES **762,000** UTILITY CUSTOMERS

2,241 EMPLOYEES **2,969** MW INSTALLED ELECTRIC GENERATING CAPACITY[1]

15 YEAR AVERAGE CONTRACT LENGTH OF POWER PURCHASE AGREEMENTS

12,629 KM OF GAS DISTRIBUTION LINES **59** HYDROELECTRIC GENERATORS

20,827 KM OF ELECTRICITY DISTRIBUTION LINES **463,236** SOLAR PANELS

3,890 KM OF WATER DISTRIBUTION MAINS **713** WIND TURBINES

[1] Includes 1,424 net MW of rate-base generation within Liberty Utilities

2017 LETTER TO SHAREHOLDERS

DEAR FELLOW SHAREHOLDERS,

For Algonquin Power and Utilities Corp., 2017 represented another remarkable year; transformational growth in our North American utilities operations, completion of new renewable energy generating facilities and the unveiling of our strategy for international expansion, all while delivering record financial results.

Our strong financial performance in 2017 can be traced to continued successful execution on our growth strategies, including the acquisition of The Empire District Electric Company. We achieved a number of important milestones in 2017: our asset base has now crested $10 billion and we completed our first investment outside of North America. From this expanded platform, we remain focused on the continued delivery of industry leading growth and value creation for our shareholders.

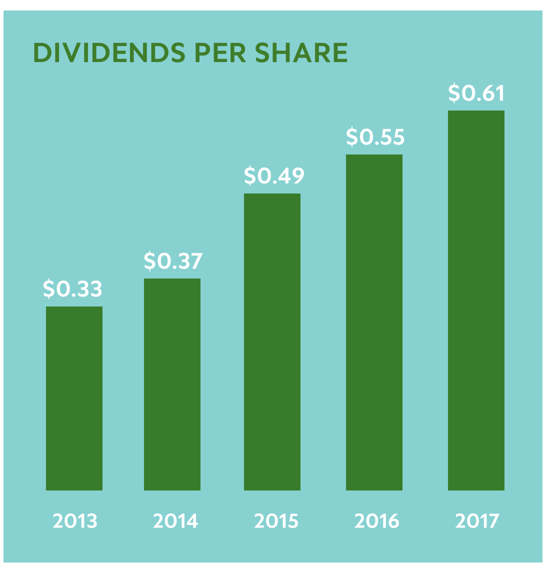
As always, our success can be directly attributed to our dedicated and growing team of power and utility professionals. As our organization continues to grow, our people remain focused on APUC's vision—to be the utility company most admired by its customers, communities and investors for its people, passion, and performance.

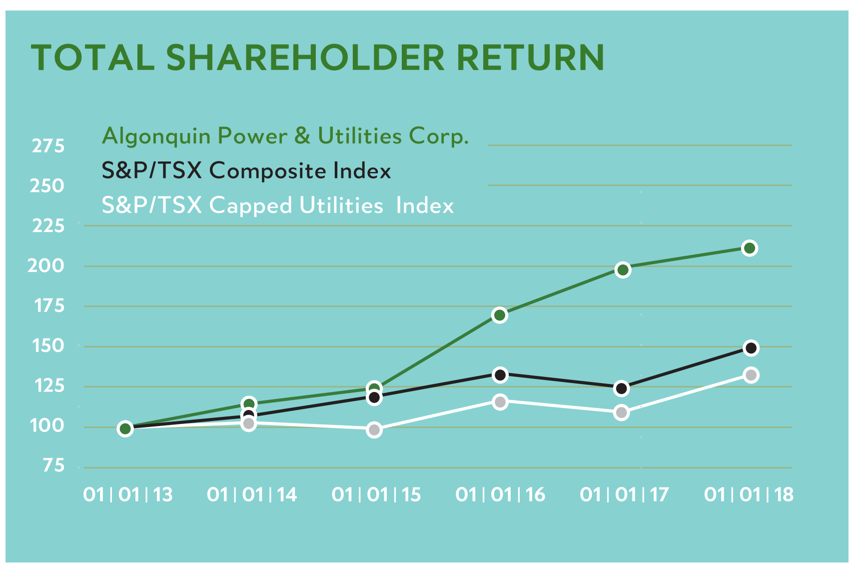
LONG TERM SUSTAINABLE GROWTH DELIVERS SHAREHOLDER VALUE

APUC's value proposition is founded on delivering a compelling total shareholder return ("TSR") to our investors which is comprised of share price appreciation and a safe and growing dividend supported by per share earnings growth.

We are very pleased to have achieved strong performance on both fronts in 2017. Our sustained financial performance powered by our acquisition of Empire supported the decision by our Board of Directors to approve a 10% increase in our dividend in January, 2017. This marked our seventh consecutive year of double-digit annual dividend growth, a cadence of which we are proud.

Dividend growth in 2017 was supported by year-over-year adjusted earnings per share growth of 30% and adjusted funds from operations growth of 72%. Consistent execution against our corporate objectives has supported a level of share performance that is among the highest of our peers. Our 2017 TSR of 26.3% was materially above the comparable Canadian benchmarks, and our





average annual return over the past five years of 19.6% is a positive reflection of the efforts we have made to profitably expand our business.

A TRANSFORMATIONAL YEAR OF GROWTH FOR LIBERTY UTILITIES

On January 1, 2017, a transformative milestone was reached by our Liberty Utilities Business Group with the completion of the Empire acquisition. The growth in the scale of our regulated utility business through this acquisition was profound. We welcomed over 800 new members to our Liberty Utilities team and assumed responsibility to provide safe, reliable, and affordable electric, natural gas and water service to more than 200,000 new customers. Through the dedicated efforts of our combined workforce, the integration of the businesses has been seamless to our customers, regulators, and investors.

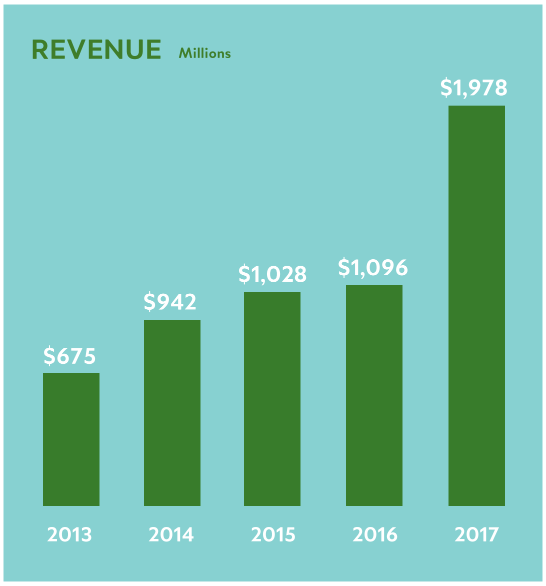
During 2017, we unveiled one of the driving factors behind the acquisition of Empire. Persistent improvement in the cost-competitiveness of renewable generation has supported our "Greening the Fleet" initiative to bring up to 800 MW of new wind generation to replace coal fired generation in the Midwest through our Customers Savings Plans program. This builds on our success in California where we commissioned 50 MW of solar generation dedicated to serving the needs of our California electric customers.

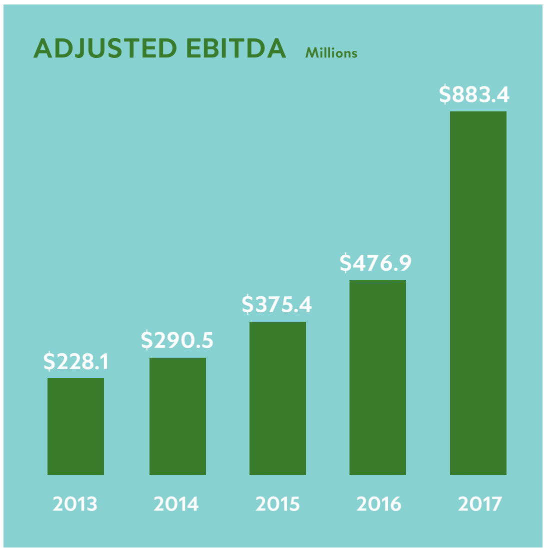
STRONG PERFORMANCE WITHIN LIBERTY POWER

We re-branded our non-regulated renewable generation group in 2017 under the "Liberty Power" banner, symbolizing the converging role that the development of renewable energy resources is playing in the delivery of regulated electric utility services. The year was marked by further expansion and diversification of our Liberty Power generating portfolio with the commissioning of our 150 MW Deerfield wind project in Michigan and an additional 10 MW solar project in California. Material progress was also made on our development opportunities, with construction in full swing on both our 75 MW Amherst Island wind project in Ontario and our 75 MW Great Bay solar project in Maryland. Development efforts also continue for additional commercially secured projects representing approximately $400 million of investment potential.

EXPANDING OUR INVESTMENT HORIZONS BEYOND NORTH AMERICA

In late 2017, APUC expanded its business into the international energy and water infrastructure arena. On November 1, 2017, APUC announced that it had formed AAGES, a new joint venture development entity focused on the development of energy and water infrastructure projects on a global scale. Through AAGES, APUC has gained access to a curated collection of international project initiatives. Our partner in the joint venture, Seville, Spain-based Abengoa, S.A., has a 70-year track





record of providing engineering and construction activities to a global client base.

Concurrent with the formation of AAGES, we announced a US$608 million equity investment in Atlantica, an owner and proven operator of a diverse, contracted portfolio of 22 infrastructure facilities representing 1.7 GW of clean power generating capacity, 1,770 km of electric transmission lines, and two desalination plants in selected global markets. Atlantica's portfolio is complementary to APUC's existing operations, and APUC's commitment to AAGES is expected to strengthen Atlantica's prospects through the addition of new assets, thereby accelerating the growth of its cash available for distribution.

OUR COMMITMENT TO RESPONSIBLE, SUSTAINABLE GROWTH AND OPERATIONS

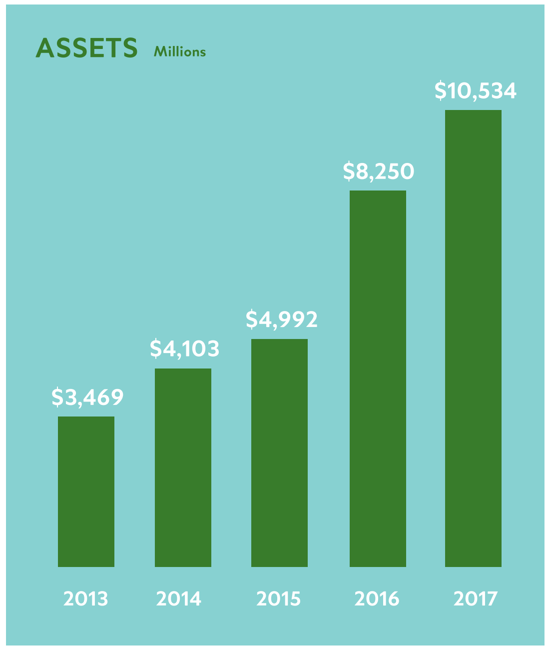
Over the course of 2017, we saw the continued evolution of our corporate governance practices with the goal of remaining at the forefront of the perpetual change taking place in this area. During the year, we established a Risk Committee within our Board of Directors that brings additional oversight and prominence to our Enterprise Risk Management function. We also strengthened our commitment to diversity, both through the adoption of a company-wide Diversity Policy as well as our membership the in "30% Club" which recognizes the important benefits that a gender diverse board and management team can bring to APUC.

We continued to pursue and promote responsible and sustainable business practices throughout our operations during 2017, including proudly marking our 10th consecutive year of reporting under the Carbon Disclosure Project.

INDUSTRY CHANGES BRING FUTURE OPPORTUNITIES

It is becoming increasingly evident that transformative changes are under way in the provision of utility services. Technological advancements coupled with evolving customer desires for greater influence and control are driving continuing change in an industry once dominated by slow moving monopolies. Technologies such as low cost renewable solar generation and flexible energy storage are ready to play an essential part in the utility of the future. We continue to apply our entrepreneurial spirit to generate new opportunities from these changes and are confident in our role in creating a sustainable energy and water future.

Our strategy for 2018 is focused on setting the stage for international investment, advancing our "Greening the Fleet" plan in the Midwest region, and seeking new project opportunities for our renewables business. An essential component of our long-term strategic plan is to make the investments necessary to fortify our systems, improve the resilience of our company as a whole, and equip our businesses to capitalize on the rapid changes taking place in our core markets. These initiatives will enable material investment



It is our belief that the slow-moving, conservative utility of the past must now embrace an agile and entrepreneurial mindset and culture to thrive in the utility business for the long term.

opportunities and a cost-effective means to meet the changing needs of our customers.

BUILDING OUR FUTURE WITH OUR PEOPLE

Through the dedication of our highly capable team of employees, APUC delivered strong performance and reached a number of important milestones in 2017. We are grateful for the productive relationships our employees continue to cultivate with our customers, landowners, suppliers, local communities, and regulators. This past year, we welcomed new members to our family of companies and we look forward to growing together with them as we expand our businesses outside our current borders. Our gratitude also goes to our Board of Directors, whose oversight and guidance has been invaluable as we build a resilient and thriving business. Finally, we would like to express our sincere appreciation to our shareholders for the support they continue to provide us.

We look forward to the future confidently, ready to embrace new opportunities.

Ian Robertson
CEO

Ken Moore
Chairman of the
Board of Directors

Our "Why" - We believe the world needs a sustainable energy and water future, and together, we are creating something special that will make a real difference to all of our stakeholders.

ALGONQUIN
Power & Utilities Corp.

Management Discussion & Analysis

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

Management of Algonquin Power & Utilities Corp. ("APUC" or the "Company" or the "Corporation") has prepared the following discussion and analysis to provide information to assist its shareholders' understanding of the financial results for the three and twelve months ended December 31, 2017. This Management Discussion & Analysis ("MD&A") should be read in conjunction with APUC's consolidated financial statements for the years ended December 31, 2017 and 2016. This material is available on SEDAR at www.sedar.com and on the APUC website at www.AlgonquinPowerandUtilities.com. Additional information about APUC, including the most recent Annual Information Form ("AIF") can be found on SEDAR at www.sedar.com.

Unless otherwise indicated, financial information provided for the years ended December 31, 2017 and 2016 has been prepared in accordance with generally accepted accounting principles in the United States ("U.S. GAAP"). As a result, the Company's financial information may not be comparable with financial information of other Canadian companies that provide financial information on another basis.

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

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

Forward-looking Statements and Forward-Looking Information

This document may contain statements that constitute "forward-looking statements" or "forward-looking information" within the meaning of applicable securities legislation (collectively, "forward-looking information"). The words "anticipates", "believes", "budget", "could", "estimates", "expects", "forecasts", "intends", "may", "might", "plans", "projects", "schedule", "should", "will", "would" and similar expressions are often intended to identify forward-looking information, although not all forward-looking information contains these identifying words. Specific forward-looking information in this document includes, but are not limited to, statements relating to: expected future growth and results of operations; liquidity, capital resources and operational requirements; rate cases, including resulting decisions and rates and expected impacts and timing; sources of funding, including adequacy and availability of credit facilities, debt maturation and future borrowings; ongoing and planned acquisitions, projects and initiatives, including expectations regarding costs, financing, results and completion dates; expectations regarding the cost of operations, capital spending and maintenance, and the variability of those costs; expected future capital investments, including expected timing, investment plans and impacts; expectations regarding generation availability, capacity and production; expectations regarding the outcome of existing or potential legal and contractual claims and disputes; expectations regarding the ability to access the capital market on reasonable terms; strategy and goals; contractual obligations and other commercial commitments; environmental liabilities; dividends to shareholders; expectations regarding the impact of tax reforms; credit ratings; anticipated growth and emerging opportunities in APUC's target markets; accounting estimates; interest rates; currency exchange rates; and commodity prices. All forward-looking information is given pursuant to the "safe harbor" provisions of applicable securities legislation.

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

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

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

Non-GAAP Financial Measures

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

Adjusted EBITDA

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

Adjusted Net Earnings

Adjusted Net Earnings is a non-GAAP measure used by many investors to compare net earnings from operations without the effects of certain volatile primarily non-cash items that generally have no current economic impact or items such as acquisition expenses or litigation expenses that are viewed as not directly related to a company's operating performance. APUC uses Adjusted Net Earnings to assess its performance without the effects of (as applicable): gains or losses on foreign exchange, foreign exchange forward contracts, interest rate swaps, acquisition costs, one-time costs of arranging tax equity financing, litigation expenses and write down of intangibles and property, plant and equipment, earnings or loss from discontinued operations, unrealized mark-to-market revaluation impacts, and other typically non-recurring items as these are not reflective of the performance of the underlying business of APUC. For 2017, the one-time impact of the revaluation of U.S. non-regulated net deferred income tax assets as a result of the U.S. federal corporate income tax rate reduction from 35% to 21% enacted in December 2017 is adjusted as it is also considered a non-recurring item not reflective of the performance of the underlying business of APUC. APUC believes that analysis and presentation of net earnings or loss on this basis will enhance an investor's understanding of the operating performance of its businesses. It is not intended to be representative of net earnings or loss determined in accordance with U.S. GAAP, which can be impacted positively or negatively by these items.

Adjusted Funds from Operations

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

Net Energy Sales

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

Net Utility Sales

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

Divisional Operating Profit

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

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

Overview and Business Strategy

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

APUC's current quarterly dividend to shareholders is U.S. $0.1165 per common share or U.S. $0.4660 per common share per annum. Based on exchange rates as at February 28, 2018, the quarterly dividend is equivalent to Cdn $0.1492 per common share or Cdn $0.5969 per common share per annum. APUC believes its annual dividend payout allows for both an immediate return on investment for shareholders and retention of sufficient cash within APUC to fund growth opportunities. Changes in the level of dividends paid by APUC are at the discretion of the APUC Board of Directors (the "Board"), with dividend levels being reviewed periodically by the Board in the context of cash available for distribution and earnings together with an assessment of the growth prospects available to APUC. APUC strives to achieve its results in the context of a moderate risk profile consistent with top-quartile North American power and utility operations.

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

Liberty Power Group

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

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

Liberty Utilities Group

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

The Liberty Utilities Group's regulated electrical distribution utility systems and related generation assets are located in the States of California, New Hampshire, Missouri, Kansas, Oklahoma, and Arkansas. The electric utility systems in total serve approximately 265,000 electric connections and operate a fleet of generation assets with a net capacity of 1,424 MW.

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

The Liberty Utilities Group's regulated water distribution and wastewater collection utility systems are located in the States of Arizona, Arkansas, California, Illinois, Missouri, and Texas which together serve approximately 160,000 connections.

Corporate Development

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

2017 Major Highlights

Corporate Highlights

Strong Year of Operating Results

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

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

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

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

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

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

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

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

Completion of The Empire District Electric Company Acquisition and Financing

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

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

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

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

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

U.S. $750 Million Private Placement Offering

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

Corporate Financings Completed:

$576 Million Bought Deal Offering of Common Shares

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

U.S. Tax Reform

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

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

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

The Company expects its effective tax rate in 2018 on its consolidated worldwide net income to be below 20%.

Additional detail on U.S. Tax Reform can be found later in this document under Corporate and Other expenses.

Change to U.S. Dollar Reporting

Effective the first quarter of 2018, APUC's interim and annual consolidated financial statements will be reported in U.S. dollars.

Over 90% of APUC's consolidated revenue, EBITDA and assets are derived from operations in the United States. In addition, APUC's dividend is denominated in U.S. dollars and the Company's common shares are listed on the New York Stock Exchange. The Company believes that the change in reporting to U.S. dollars will provide improved information to investors and allow for better assessment of its results without the effects of the change in currency on 90% of its operations.

Liberty Power Group Highlights

Completion of the Deerfield Wind Project

On February 21, 2017, the Deerfield Wind Facility achieved commercial operations ("COD"). The project consists of a 150 MW wind generating facility located in central Michigan. On May 10, 2017, tax equity financing of approximately U.S. $166.6 million was completed. The Deerfield Wind Facility is the Liberty Power Group's tenth wind generating facility and consists of 44 Vestas V110-2.0 wind turbines and 28 Vestas V110-2.2 turbines and is expected to generate 555.2 GW-hrs annually. The project has a 20 year Power Purchase Agreement ("PPA") with a local electric distribution utility serving approximately 260,000 customers in Michigan.

Completion of the Bakersfield II Solar Project

On January 11, 2017, the Liberty Power Group achieved COD on the 10 MWac solar generating facility located in Kern County, California (the "Bakersfield II Solar Facility"). On February 28, 2017, tax equity financing of approximately U.S. $12.3 million was completed. The Bakersfield II Solar Facility is the Liberty Power Group's third solar generating facility and is comprised of approximately 38,640 solar panels located on 64 acres of land. The project is expected to generate 24.2 GW-hrs of energy annually. The project has a 20 year PPA with a large investment grade electric utility in California.

Issuance of $300 million Senior Unsecured Debentures

On January 17, 2017, the Liberty Power Group issued $300.0 million of senior unsecured debentures bearing interest at 4.09% and with a maturity date of February 17, 2027. The debentures were sold at a price of $99.929 per $100.00 principal amount. Concurrent with the offering, the Liberty Power Group entered into a cross currency swap, coterminous with the debentures, to economically convert the Canadian dollar denominated offering into U.S. dollars.

The net proceeds were used to partially finance the Odell Wind, Deerfield Wind and Bakersfield II Solar projects.

Liberty Utilities Group Highlights

Successful Rate Case Outcomes

A core strategy of the Liberty Utilities Group is to ensure an appropriate return is earned on the rate base at its various utility systems. During 2017, the Liberty Utilities Group successfully completed several rate cases representing a cumulative annualized revenue increase of approximately U.S. $20.4 million. The Liberty Utilities Group has pending rate case filings in progress that are expected to be completed in 2018 that if successful will represent an increase in rates in the amount of U.S. $44.9 million.

Application to Develop up to 800 MW of Wind in the Midwest

On October 31, 2017, Empire announced a proposed plan to phase out its Asbury coal generation facility and expand its wind resources with the development of up to an additional 800 MW of strategically located wind generation in or near its service territory by the end of 2020. The plan projects cost savings for customers of U.S. $172.0 - U.S. $325.0 million over a twenty-year period. Empire filed a request for approval of the wind expansion initiative with regulators in Missouri, Kansas, Oklahoma, and Arkansas, and the project is subject to their respective review. Orders from the various jurisdictions are anticipated by June 2018.

Granite Bridge Project

On December 4, 2017, the Liberty Utilities Group announced plans for the development of a new infrastructure project designed to bring additional natural gas supply to New Hampshire's residents and businesses. The project, called Granite Bridge, would bring natural gas from existing infrastructure located in New Hampshire's Seacoast region to the central part of the state through an underground pipeline. The proposed Granite Bridge project is estimated to cost between U.S. $320.0 million and U.S. $360 million and would connect the existing Portland Natural Gas Transmission System and Maritimes and Northeast Pipeline facilities in Stratham with the existing Tennessee Gas Pipeline facilities in Manchester. The Granite Bridge project also includes a proposed Liquefied Natural Gas storage facility capable of storing up to two billion cubic feet of natural gas. The final project will be subject to approval from regulatory authorities.

Acquisition of the St. Lawrence Gas Company, Inc.

On August 31, 2017, the Company entered into a definitive agreement to acquire St. Lawrence Gas Company, Inc. ("SLG"). SLG is a rate-regulated natural gas distribution utility serving approximately 16,000 customers in northern New York State. The total purchase price for the transaction is U.S. $70.0 million, less total third-party debt of SLG outstanding at closing, and subject to customary working capital adjustments. Closing of the transaction remains subject to regulatory approval and other closing conditions and is expected to occur in late 2018 or early 2019.

Acquisition of the Perris Water Distribution System

On August 10, 2017, the Company's board approved the acquisition of two water distribution systems serving approximately 4,000 customers in the City of Perris, California. The anticipated purchase price of U.S. $11.5 million is expected to be established as rate base during the regulatory approval process. Liberty Utilities was the successful bidder in the city's request for proposal process and in July 2017 the Perris City council voted to approve the sale to Liberty Utilities. The City of Perris residents voted to approve the sale on November 7, 2017. Liberty Utilities expects to file the advice letter to acquire the water utility with the California Public Utility Commission ("CPUC") in Q1 2018, with approval expected in late 2018.

Completion of the Luning Solar Facility

On February 15, 2017, the Liberty Utilities Group acquired control of a 50 MWac solar generating facility located in Mineral County, Nevada for approximately U.S. $110.9 million. The facility is comprised of approximately 204,784 solar panels located on 584 acres of land. The facility is expected to generate 144.6 GW-hrs of energy annually. On February 17, 2017, tax equity financing of approximately U.S. $39.0 million was completed. The net capital cost of the facility is included in the rate base of the Calpeco Electric System as energy produced from the project is being consumed by the utility's customers.

2017 Fourth Quarter Results From Operations

Key Financial Information (all dollar amounts in $ millions except per share information)	Three Months Ended December 31 2017	2016
Revenue	**$ 523.4**	$ 310.2
Net earnings attributable to shareholders	**60.0**	46.3
Cash provided by operating activities	**169.8**	121.9
Adjusted Net Earnings[1]	**85.9**	51.4
Adjusted EBITDA[1]	**233.4**	138.3
Adjusted Funds from Operations[1]	**159.1**	96.4
Dividends declared to common shareholders	**64.0**	39.2
Weighted average number of common shares outstanding	**412,632,308**	273,952,963
Per share		
Basic net earnings	**$ 0.14**	$ 0.16
Diluted net earnings	**$ 0.14**	$ 0.16
Adjusted Net Earnings[1,2]	**$ 0.20**	$ 0.18
Dividends declared to common shareholders	**$ 0.15**	$ 0.14

1 See Non-GAAP Financial Measures

2 APUC uses per share Adjusted Net Earnings to enhance assessment and understanding of the performance of APUC.

For the three months ended December 31, 2017, APUC experienced an average U.S. exchange rate of approximately 1.2715 as compared to 1.3343 in the same period in 2016. As such, any quarter over quarter variance in revenue or expenses, in local currency, at any of APUC's U.S. entities is affected by a change in the average exchange rate upon conversion to APUC's reporting currency.

For the three months ended December 31, 2017, APUC reported total revenue of $523.4 million as compared to $310.2 million during the same period in 2016, an increase of $213.2 million. The major factors resulting in the increase in APUC revenue in the three months ended December 31, 2017 as compared to the corresponding period in 2016 are set out as follows:

(all dollar amounts in $ millions)		Three Months Ended December 31
Comparative Prior Period Revenue	**$**	**310.2**
LIBERTY POWER GROUP		
Existing Facilities		
Hydro: Decrease due to lower pricing in Hydro Quebec PPA renewals and a decline in pricing in the Western Region, partially offset by higher overall production.		(0.4)
Wind Canada: Increase primarily due to higher production and annual rate increases in PPAs.		1.9
Wind U.S.: Increase primarily due to higher overall production.		1.3
Solar Canada: Increase primarily due to higher production.		0.1
Solar U.S.: Increase primarily due to higher production.		0.1
Thermal: Increase is primarily due to higher overall production as well as a new capacity-based contract at the Sanger Thermal Facility.		2.9
Other:		(0.5)
		5.4
New Facilities		
Wind US: Acquisition of Deerfield Wind Facility in March 2017.		9.5
Solar US: Bakersfield II Solar Facility was placed in service in December 2016.		0.3
		9.8
Foreign Exchange		**(2.3)**
LIBERTY UTILITIES GROUP		
Existing Facilities		
Electricity: Decrease primarily due to retroactive recognition of 12 months of revenue in Q4 of 2016 arising from the 2016 rate case at the Calpeco Electric System.		(7.2)
Gas: Increase primarily due to higher demand and pass through gas costs at the New England and Midstates Gas Systems from increased heating degree days, partially offset by lower pass through gas costs at the EnergyNorth Gas System.		14.5
Water: Decrease primarily due to divestiture of Mountain Water System from condemnation proceedings on June 22, 2017.		(2.9)
Other: Decrease primarily due to lower contracted services.		(1.8)
		2.6
New Facilities		
Electricity: Acquisition of both Empire's electric distribution system ($180.8 million) on January 1, 2017 and the Luning Solar Facility ($3.6 million) on February 15, 2017.		184.4
Gas: Acquisition of Empire's gas distribution system on January 1, 2017.		14.6
Water: Acquisition of Empire's water distribution system on January 1, 2017.		0.6
Other: Acquisition of Empire's fiber optic operations on January 1, 2017.		2.0
		201.6
Rate Cases		
Electricity: Implementation of new rates at the Granite State Electric System.		1.0
Gas: Implementation of new rates at the EnergyNorth, Midstates, New England, and Peach State Gas Systems.		4.1
Water: Implementation of new rates at the Park Water System.		2.0
		7.1
Foreign Exchange		**(11.0)**
Current Period Revenue	**$**	**523.4**

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

For the three months ended December 31, 2017, net earnings attributable to shareholders totaled $60.0 million as compared to $46.3 million during the same period in 2016, an increase of $13.7 million or 29.6%. The increase was due to a $101.6 million increase in earnings from operating facilities and a $1.1 million decrease in acquisition related costs. These items were partially offset by a $5.6 million increase in administration charges, $35.4 million increase in depreciation and amortization expenses, $0.3 million decrease in foreign exchange gain, $3.7 million increase in interest expense, $0.6 million decrease in interest, dividend, equity and other income, $3.3 million decrease in other gains, $2.3 million decrease in gains on long lived assets, $8.9 million decrease in gains from derivative instruments, $2.4 million decrease in net effect of non-controlling interests, and a $26.5 million increase in income tax expense (tax explanations are discussed in *APUC: Corporate and Other Expenses)* as compared to the same period in 2016.

During the three months ended December 31, 2017, cash provided by operating activities totaled $169.8 million as compared to cash provided by operating activities of $121.9 million during the same period in 2016. During the three months ended December 31, 2017, Adjusted Funds from Operations totaled $159.1 million compared to Adjusted Funds from Operations of $96.4 million during the same period in 2016. The change in Adjusted Funds from Operations in the three months ended December 31, 2017 is primarily due to increased earnings from operations (including Empire) as compared to the same period in 2016.

During the three months ended December 31, 2017, Adjusted EBITDA totaled $233.4 million as compared to $138.3 million during the same period in 2016, an increase of $95.1 million or 68.8%. A more detailed analysis of these factors is presented within the reconciliation of Adjusted EBITDA to net earnings set out below (see *Non-GAAP Financial Measures*).

2017 Annual Results From Operations

Key Financial Information

(all dollar amounts in $ millions except per share information)	Twelve Months Ended December 31		
	2017	**2016**	**2015**
Revenue	**$ 1,977.8**	$ 1,096.0	$ 1,027.9
Net earnings attributable to shareholders from continuing operations	**193.1**	130.9	118.5
Net earnings attributable to shareholders	**193.1**	130.9	117.5
Cash provided by operating activities	**457.8**	287.9	261.9
Adjusted Net Earnings[1]	**292.1**	161.6	121.5
Adjusted EBITDA[1]	**883.4**	476.9	375.4
Adjusted Funds from Operations[1]	**614.5**	356.4	287.4
Dividends declared to common shareholders	**242.5**	149.2	124.8
Weighted average number of common shares outstanding	**382,323,434**	271,832,430	253,172,088
Per share			
Basic net earnings from continuing operations	**$ 0.48**	$ 0.44	$ 0.43
Basic net earnings	**$ 0.48**	$ 0.44	$ 0.42
Diluted net earnings	**$ 0.47**	$ 0.44	$ 0.42
Adjusted Net Earnings[1,2]	**$ 0.74**	$ 0.57	$ 0.46
Dividends declared to common shareholders	**$ 0.61**	$ 0.55	$ 0.49
Total assets	**10,533.6**	8,249.5	4,991.7
Long term debt[3]	**3,864.5**	4,272.0	1,486.8

1 See Non-GAAP Financial Measures.

2 APUC uses per share Adjusted Net Earnings to enhance assessment and understanding of the performance of APUC.

3 Includes current and long-term portion of debt and convertible debentures per the financial statements.

For the twelve months ended December 31, 2017, APUC experienced an average U.S. exchange rate of approximately 1.2980 as compared to 1.3253 in the same period in 2016. As such, any year-over-year variance in revenue or expenses, in local currency, at any of APUC's U.S. entities is affected by a change in the average exchange rate upon conversion to APUC's reporting currency.

For the twelve months ended December 31, 2017, APUC reported total revenue of $1,977.8 million as compared to $1,096.0 million during the same period in 2016, an increase of $881.8 million or 80.5%. The major factors resulting in the increase in APUC revenue for the twelve months ended December 31, 2017 as compared to the corresponding period in 2016 are set out as follows:

(all dollar amounts in $ millions)		Twelve Months Ended December 31
Comparative Prior Period Revenue	**$**	**1,096.0**
LIBERTY POWER GROUP		
Existing Facilities		
Hydro: Decrease primarily due to prior year recognition of a Global Adjustment payment from the Ontario IESO, and lower pricing in Hydro Quebec PPA renewals, coupled with lower production in the Maritime and Western Regions.		(7.5)
Wind Canada: Increase primarily due to higher production and annual PPA rate increases.		2.2
Wind U.S.: Decrease primarily due to lower REC pricing, partially offset by higher production at Minonk and Shady Oaks Wind Facilities.		(0.8)
Solar Canada: Decrease primarily due to lower production, largely in the second quarter of 2017.		(0.6)
Solar U.S.: Decrease primarily due to business interruption insurance payments received in the prior year.		(0.4)
Thermal: Increase primarily due to higher pass through fuel costs at the Windsor Locks Thermal Facility, as well as a new capacity-based contract at the Sanger Thermal Facility.		4.2
Other: Decrease primarily due to the shutdown of the hydro mulch business at the Sanger Thermal Facility.		(1.9)
		(4.8)
New Facilities		
Wind U.S.: Acquisition of Odell (September 2016) and Deerfield (March 2017) Wind Facilities.		40.8
Solar U.S.: Bakersfield II Solar Facility was placed in service in December 2016.		2.1
		42.9
Foreign Exchange		**(3.6)**
LIBERTY UTILITIES GROUP		
Existing Facilities		
Electricity: Decrease primarily due to lower pass through energy costs at the Calpeco Electric System.		(8.3)
Gas: Increase primarily due to higher consumption at the EnergyNorth and New England Gas Systems due to higher heating degree days combined with higher pass through gas costs at the Peach State Gas System.		38.0
Water: Decrease primarily due divestiture of Mountain Water System from condemnation proceedings on June 22, 2017.		(6.5)
Other: Decrease primarily due to lower contracted services.		(6.0)
		17.2
New Facilities		
Electricity: Acquisition of both Empire's electric distribution system ($754.6 million) on January 1, 2017 and the Luning Solar Facility ($14.7 million) on February 15, 2017.		769.3
Gas: Acquisition of Empire's gas distribution system on January 1, 2017.		46.9
Water: Acquisition of Empire's water distribution system on January 1, 2017.		2.7
Other: Acquisition of Empire's fiber optic operations on January 1, 2017.		8.1
		827.0
Rate Cases		
Electricity: Implementation of new rates at the Granite State Electric System.		5.2
Gas: Implementation of new rates at the EnergyNorth, Midstates, New England, and Peach State Gas Systems.		12.5
Water: Implementation of new rates at the Park Water, Bella Vista, Rio Rico and Black Mountain Water and Wastewater Systems.		6.1
		23.8
Foreign Exchange		**(20.7)**
Current Period Revenue	**$**	**1,977.8**

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

For the twelve months ended December 31, 2017, net earnings attributable to shareholders totaled $193.1 million as compared to $130.9 million during the same period in 2016, an increase of $62.2 million. The increase was due to a $401.4 million increase in earnings from operating facilities, $1.4 million increase in interest, dividend, equity and other income, and $23.6 million increase in net effect of non-controlling interests. These items were partially offset by an $18.2 million increase in administration charges, $139.5 million increase in depreciation and amortization expenses, $0.8 million decrease in foreign exchange gains, $71.0 million increase in interest expense, $11.8 million decrease in other gains, $50.8 million increase in acquisition costs, $0.8 million decrease in gain on long lived assets, $13.2 million decrease on gains from derivative instruments and $58.1 million increase in income tax expense (tax explanations are discussed in *APUC: Corporate and Other Expenses*) as compared to the same period in 2016.

During the twelve months ended December 31, 2017, cash provided by operating activities totaled $457.8 million as compared to cash provided by operating activities of $287.9 million during the same period in 2016. During the twelve months ended December 31, 2017, Adjusted Funds from Operations, a non-GAAP measure, totaled $614.5 million as compared to Adjusted Funds from Operations of $356.4 million the same period in 2016, an increase of $258.1 million.

Adjusted EBITDA in the twelve months ended December 31, 2017 totaled $883.4 million as compared to $476.9 million during the same period in 2016, an increase of $406.5 million or 85.2%. A detailed analysis of this variance is presented within the reconciliation of Adjusted EBITDA to net earnings set out below (see *Non-GAAP Financial Measures*).

2017 Adjusted EBITDA Summary

Adjusted EBITDA (see *Non-GAAP Financial Measures*) for the three months ended December 31, 2017 totaled $233.4 million as compared to $138.3 million during the same period in 2016, an increase of $95.1 million or 68.8%. Adjusted EBITDA for the twelve months ended December 31, 2017 totaled $883.4 million as compared to $476.9 million during the same period in 2016, an increase of $406.5 million or 85.2%. The breakdown of Adjusted EBITDA by the Company's main operating segments and a summary of changes are shown below.

Adjusted EBITDA by business units	Three Months Ended December 31		Twelve Months Ended December 31	
(all dollar amounts in $ millions)	2017	2016	2017	2016
Liberty Power Operating Profit	**$ 70.8**	$ 61.9	**$ 250.9**	$ 217.3
Liberty Utilities Group Operating Profit	**180.7**	85.9	**694.1**	300.5
Administrative Expenses	**(18.7)**	(13.1)	**(64.5)**	(46.3)
Other Income & Expenses	**0.6**	3.6	**2.9**	5.4
Total Algonquin Power & Utilities Adjusted EBITDA	**$ 233.4**	$ 138.3	**$ 883.4**	$ 476.9
Change in Adjusted EBITDA ($)	**$ 95.1**		**$ 406.5**	
Change in Adjusted EBITDA (%)	**68.8%**		**85.2%**	

Change in Adjusted EBITDA	Three Months Ended December 31, 2017			
(all dollar amounts in $ millions)	Power	Utilities	Corporate	Total
Prior period balances	**$ 61.9**	**$ 85.9**	**$ (9.5)**	**$ 138.3**
Existing Facilities	7.8	(5.6)	(3.0)	(0.8)
New Facilities	3.0	97.3	—	100.3
Rate Cases	—	7.1	—	7.1
Foreign Exchange Impact	(1.9)	(4.0)	—	(5.9)
Administrative Expenses	—	—	(5.6)	(5.6)
Total change during the period	**$ 8.9**	**$ 94.8**	**$ (8.6)**	**$ 95.1**
Current period balances	**$ 70.8**	**$ 180.7**	**$ (18.1)**	**$ 233.4**

Change in Adjusted EBITDA	Twelve Months Ended December 31, 2017			
(all dollar amounts in $ millions)	Power	Utilities	Corporate	Total
Prior period balances	**$ 217.3**	**$ 300.5**	**$ (40.9)**	**$ 476.9**
Existing Facilities	0.9	(4.5)	(2.6)	(6.2)
New Facilities	34.9	381.0	—	415.9
Rate Cases	—	23.8	—	23.8
Foreign Exchange Impact	(2.2)	(6.7)	—	(8.9)
Administration Expenses	—	—	(18.1)	(18.1)
Total change during the period	**$ 33.6**	**$ 393.6**	**$ (20.7)**	**$ 406.5**
Current period balances	**$ 250.9**	**$ 694.1**	**$ (61.6)**	**$ 883.4**

2017 Electricity Generation Performance

(Performance in GW-hrs sold)	Long Term Average Resource	Three Months Ended December 31 2017	Three Months Ended December 31 2016	Long Term Average Resource	Twelve Months Ended December 31 2017	Twelve Months Ended December 31 2016
Hydro Facilities:						
Maritime Region	**37.6**	**34.9**	21.9	**148.2**	**129.7**	144.1
Quebec Region	**72.6**	**67.5**	64.0	**273.3**	**270.6**	267.5
Ontario Region	**31.9**	**30.6**	28.6	**136.0**	**129.5**	126.8
Western Region	**12.6**	**10.5**	18.1	**65.0**	**59.6**	66.1
	154.7	**143.5**	132.6	**622.5**	**589.4**	604.5
Wind Facilities:						
St. Damase	**22.7**	**24.0**	20.4	**76.9**	**74.3**	74.4
St. Leon	**121.4**	**138.7**	130.8	**430.2**	**444.2**	417.3
Red Lily[1]	**24.1**	**29.2**	25.4	**88.5**	**91.6**	82.6
Morse	**30.5**	**33.1**	27.7	**108.8**	**106.4**	94.8
Sandy Ridge	**43.6**	**42.0**	51.8	**158.3**	**153.3**	155.8
Minonk	**189.8**	**203.5**	184.9	**673.7**	**673.7**	635.8
Senate	**140.0**	**126.6**	136.7	**520.4**	**492.8**	504.4
Shady Oaks	**100.5**	**108.7**	104.4	**355.6**	**365.5**	323.9
Odell[2]	**238.0**	**244.6**	211.2	**831.8**	**807.2**	297.7
Deerfield[3]	**160.0**	**164.3**	—	**472.6**	**449.3**	—
	1,070.6	**1,114.7**	893.3	**3,716.8**	**3,658.3**	2,586.7
Solar Facilities:						
Cornwall	**2.2**	**2.1**	1.9	**14.7**	**14.4**	15.6
Bakersfield I	**8.9**	**8.7**	7.4	**52.8**	**48.3**	45.9
Bakersfield II[4]	**4.1**	**4.0**	—	**24.4**	**22.2**	—
	15.2	**14.8**	**9.3**	**91.9**	**84.9**	**61.5**
Renewable Energy Performance	**1,240.5**	**1,273.0**	1,035.2	**4,431.2**	**4,332.6**	3,252.7
Thermal Facilities:						
Windsor Locks	**N/A[5]**	**31.8**	30.9	**N/A[5]**	**122.0**	131.0
Sanger	**N/A[5]**	**33.5**	28.8	**N/A[5]**	**86.0**	118.7
		65.3	59.7		**208.0**	249.7
Total Performance		**1,338.3**	1,094.9		**4,540.6**	3,502.4

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

[2] The Odell Wind Facility achieved COD on July 29, 2016 and was treated as an equity investment until September 15, 2016 at which time the Company acquired the remaining 50% ownership in the facility.

[3] The Deerfield Wind Facility achieved COD on February 21, 2017 and was treated as an equity investment until March 14, 2017 at which time the Company acquired the remaining 50% ownership in the facility. The long-term average resources ("LTAR") and production noted above represents all production from the date of COD.

[4] The Bakersfield II Solar Facility achieved COD on January 11, 2017 in accordance with the terms of the PPA. The LTAR and production noted above represents all production from the date of COD.

[5] Natural gas fired co-generation facility.

2017 Fourth Quarter Liberty Power Group Performance

For the three months ended December 31, 2017, the Liberty Power Group generated 1,338.3 GW-hrs of electricity as compared to 1,094.9 GW-hrs during the same period of 2016.

For the three months ended December 31, 2017, the hydro facilities generated 143.5 GW-hrs of electricity as compared to 132.6 GW-hrs produced in the same period in 2016, an increase of 8.2%. Electricity generated represented 92.8% of long-term average resources ("LTAR") as compared to 85.7% during the same period in 2016. During the quarter, all regions were below their respective LTAR.

For the three months ended December 31, 2017, the wind facilities produced 1,114.7 GW-hrs of electricity as compared to 893.3 GW-hrs produced in the same period in 2016, an increase of 24.8%. The higher generation was primarily due to the addition of the Deerfield Wind Facility which achieved COD on February 21, 2017. This increase was partially offset by lower production at the Senate and Sandy Ridge Wind Facilities. During the three months ended December 31, 2017, the wind facilities (excluding the Deerfield Wind Facility) generated electricity equal to 104.3% of LTAR as compared to 98.0% during the same period in 2016.

For the three months ended December 31, 2017, the solar facilities generated 14.8 GW-hrs of electricity as compared to 9.3 GW-hrs of electricity in the same period in 2016, an increase of 59.1%. The increase in production is primarily due to the addition of the Bakersfield II Solar Facility which achieved COD on January 11, 2017. The solar facilities (excluding Bakersfield II) production was 2.7% below its LTAR as compared to 16.2% below in the same period in 2016.

For the three months ended December 31, 2017, the thermal facilities generated 65.3 GW-hrs of electricity as compared to 59.7 GW-hrs of electricity during the same period in 2016. During the same period, the Windsor Locks Thermal Facility generated 136.9 billion lbs of steam as compared to 129.3 billion lbs of steam during the same period in 2016.

2017 Annual Liberty Power Group Performance

For the twelve months ended December 31, 2017, the Liberty Power Group generated 4,540.6 GW-hrs of electricity as compared to 3,502.4 GW-hrs during the same period of 2016.

For the twelve months ended December 31, 2017, the hydro facilities generated 589.4 GW-hrs of electricity as compared to 604.5 GW-hrs produced in the same period in 2016, a decrease of 2.5%. Electricity generated represented 94.7% of long-term projected average resources as compared to 97.1% during the same period in 2016. The decrease is primarily due to reduced hydrology in the Maritime and Western Region's partially offset by increased generation in the Quebec and Ontario Regions.

For the twelve months ended December 31, 2017, the wind facilities produced 3,658.3 GW-hrs of electricity as compared to 2,586.7 GW-hrs produced in the same period in 2016, an increase of 41.4%. During the twelve months ended December 31, 2017, the wind facilities generated electricity equal to 98.4% of LTAR as compared to 93.9% during the same period in 2016. The increase in production was primarily due to higher production at the Shady Oaks, Minonk and St. Leon Wind Facilities as well as the incremental electricity generated at the Deerfield and Odell Wind Facilities which achieved COD on February 21, 2017 and July 29, 2016, respectively.

For the twelve months ended December 31, 2017, the solar facilities generated 84.9 GW-hrs of electricity as compared to 61.5 GW-hrs of electricity produced in the same period in 2016, an increase of 38.0%. The increase in production is primarily due to the addition of the Bakersfield II Solar Facility which achieved COD on January 11, 2017. The solar facilities (excluding Bakersfield II) production was 7.1% below its LTAR as compared to 8.9% below in the same period in 2016.

For the twelve months ended December 31, 2017, the thermal facilities generated 208.0 GW-hrs of electricity as compared to 249.7 GW-hrs of electricity during the same period in 2016. During the same period, the Windsor Locks Thermal Facility generated 559.1 billion lbs of steam as compared to 552.5 billion lbs of steam during the same period in 2016.

2017 Liberty Power Group Operating Results

(all dollar amounts in $ millions)	Three Months Ended December 31		Twelve Months Ended December 31	
	2017	2016	2017	2016
Revenue[1]				
Hydro	**$ 14.0**	$ 14.6	**$ 58.2**	$ 66.5
Wind	**54.0**	42.6	**171.6**	128.2
Solar	**2.0**	1.6	**14.0**	12.9
Thermal	**11.1**	8.2	**38.8**	35.5
Total Revenue	**$ 81.1**	$ 67.0	**$ 282.6**	$ 243.1
Less:				
Cost of Sales - Energy[2]	**(1.9)**	(1.8)	**(6.5)**	(5.8)
Cost of Sales - Thermal	**(5.8)**	(4.4)	**(18.9)**	(15.5)
Realized gain/(loss) on hedges[3]	**—**	—	**(0.7)**	(1.0)
Net Energy Sales	**$ 73.4**	$ 60.8	**$ 256.5**	$ 220.8
Renewable Energy Credits ("REC")[4]	**5.5**	6.3	**17.1**	20.2
Other Revenue	**0.1**	0.5	**0.5**	2.4
Total Net Revenue	**$ 79.0**	$ 67.6	**$ 274.1**	$ 243.4
Expenses & Other Income				
Operating expenses	**(21.9)**	(20.2)	**(86.7)**	(72.3)
Interest, dividend, equity and other income	**1.1**	0.9	**3.7**	5.2
HLBV income[5]	**12.6**	13.6	**59.8**	41.0
Divisional Operating Profit[6,7]	**$ 70.8**	$ 61.9	**$ 250.9**	$ 217.3

1 While most of the Liberty Power Group's PPAs include annual rate increases, a change to the weighted average production levels resulting from higher average production from facilities that earn lower energy rates can result in a lower weighted average energy rate earned by the division as compared to the same period in the prior year.

2 Cost of Sales - Energy consists of energy purchases in the Maritime Region to manage the energy sales from the Tinker Hydro Facility which is sold to retail and industrial customers under multi-year contracts.

3 See financial statements *note 25(b)(iv)*.

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

5 HLBV income represents the value of net tax attributes earned by the Liberty Power Group in the period primarily from electricity generated by certain of its U.S. wind power and U.S. solar generation facilities.

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

7 See *Non-GAAP Financial Measures*.

2017 Fourth Quarter Operating Results

For the three months ended December 31, 2017, the Liberty Power Group's facilities generated $70.8 million of operating profit as compared to $61.9 million during the same period in 2016, which represents an increase of $8.9 million or 14.4%, excluding corporate administration expenses.

Highlights of the changes are summarized in the following table:

(all dollar amounts in $ millions)	Three Months Ended December 31	
Prior Period Operating Profit	**$**	**61.9**
Existing Facilities		
Hydro: Decrease due to lower pricing in Hydro Quebec PPA renewals and a decline in pricing in the Western Region, partially offset by higher overall production.		(0.6)
Wind Canada: Increase primarily due to higher production and annual PPA rate increases.		1.9
Wind U.S.: Increase primarily due to higher production and HLBV income at the Minonk and Odell Wind Facilities.		4.7
Solar Canada: Increase primarily due to higher production.		0.1
Solar U.S.: Increase primarily due to higher production.		0.3
Thermal: Increase primarily due to higher overall production as well as a new capacity-based contract at the Sanger Thermal Facility.		1.3
Other:		0.1
		7.8
New Facilities		
Wind U.S.: Acquisition of Deerfield Wind Facility in March 2017.		2.2
Solar U.S.: Bakersfield II was placed in service in December 2016.		0.8
		3.0
Foreign Exchange		**(1.9)**
Current Period Divisional Operating Profit	**$**	**70.8**

2017 Annual Operating Results

For the twelve months ended December 31, 2017, the Liberty Power Group's facilities generated $250.9 million of operating profit as compared to $217.3 million during the same period in 2016, which represents an increase of $33.6 million or 15.5%, excluding corporate administration expenses.

Highlights of the changes are summarized in the following table:

(all dollar amounts in $ millions)		Twelve Months Ended December 31
Prior Period Operating Profit	**$**	**217.3**
Existing Facilities		
Hydro: Decrease primarily due to prior year recognition of a Global Adjustment payment from the Ontario IESO, and pricing settlement in the Quebec Region, coupled with lower production in the Maritime and Western Regions.		(8.2)
Wind Canada: Increase primarily due to higher production and annual rate increases.		1.8
Wind U.S.: Increase primarily due to higher HLBV income and higher production at the Minonk and Shady Oaks Wind Facilities.		6.7
Solar Canada: Decrease primarily due to lower production, largely in the second quarter of 2017.		(0.2)
Solar U.S.: Decrease primarily due to business interruption insurance payments received in the prior year.		(0.4)
Thermal: Increase primarily due to higher pass through fuel costs at to the Windsor Locks Thermal Facility, as well as a new capacity-based contract at the Sanger Thermal Facility.		0.4
Other:		0.8
		0.9
New Facilities		
Wind U.S.: Acquisition of Odell (September 2016) and Deerfield (March 2017) Wind Facilities.		31.3
Solar U.S.: Bakersfield II was placed in service in December 2016.		3.6
		34.9
Foreign Exchange		**(2.2)**
Current Period Divisional Operating Profit	**$**	**250.9**

LIBERTY UTILITIES GROUP

The Liberty Utilities Group operates rate-regulated utilities that provide distribution services to approximately 762,000 connections in the natural gas, electric, water and wastewater sectors. On January 1, 2017, the Liberty Utilities Group completed the acquisition of Empire. Empire is a vertically-integrated utility providing electric, natural gas and water service serving approximately 221,000 customers in Missouri, Kansas, Oklahoma, and Arkansas. The Liberty Utilities Group's strategy is to grow its business organically and through business development activities while using prudent acquisition criteria. The Liberty Utilities Group believes that its business results are maximized by building constructive regulatory and customer relationships, and enhancing connections in the communities in which it operates.

Utility System Type

(all dollar amounts in U.S. $ millions)	As at December 31 2017 Assets	2017 Total Connections[1]	2016 Assets	2016 Total Connections[1]
Electricity	**$ 2,479.9**	**265,000**	$ 378.4	94,000
Natural Gas	**996.1**	**337,000**	845.9	293,000
Water and Wastewater	**462.6**	**160,000**	516.4	178,000
Total	**$ 3,938.6**	**762,000**	$ 1,740.7	565,000
Accumulated Deferred Income Taxes Liability	**$ 392.8**		$ 194.7	

[1] Total Connections represents the sum of all active and vacant connections.

The Liberty Utilities Group aggregates the performance of its utility operations by utility system type – electricity, natural gas, and water and wastewater systems.

The electric distribution systems are comprised of regulated electrical distribution utility systems and serve approximately 265,000 connections in the states of California, New Hampshire, Missouri, Kansas, Oklahoma, and Arkansas.

The natural gas distribution systems are comprised of regulated natural gas distribution utility systems and serve approximately 337,000 connections located in the states of New Hampshire, Illinois, Iowa, Missouri, Georgia, and Massachusetts.

The water and wastewater distribution systems are comprised of regulated water distribution and wastewater collection utility systems and serve approximately 160,000 connections located in the states of Arkansas, Arizona, California, Illinois, Missouri and Texas.

2017 Fourth Quarter Usage Results

Electric Distribution Systems

	Three Months Ended December 31 2017	2016
Average Active Electric Connections For The Period		
Residential	224,400	80,600
Commercial and industrial	39,200	12,500
Total Average Active Electric Connections For The Period	**263,600**	**93,100**
Customer Usage (GW-hrs)		
Residential	571.7	142.5
Commercial and industrial	882.3	225.0
Total Customer Usage (GW-hrs)	**1,454.0**	**367.5**

For the three months ended December 31, 2017, the electric distribution systems' usage totaled 1,454.0 GW-hrs as compared to 367.5 GW-hrs for the same period in 2016, an increase of 1,086.5 GW-hrs or 295.6%. The addition of Empire accounted for 1,091.6 GW-hrs of the increase. Excluding Empire, usage was 5.1 GW-hrs, or 1.4%, lower due to lower commercial usage at the Calpeco Electric System.

Natural Gas Distribution Systems

	Three Months Ended December 31	
	2017	**2016**
Average Active Natural Gas Connections For The Period		
Residential	286,700	248,100
Commercial and industrial	31,700	26,600
Total Average Active Natural Gas Connections For The Period	**318,400**	**274,700**
Customer Usage (MMBTU)		
Residential	5,196,000	3,737,000
Commercial and industrial	4,282,000	3,446,000
Total Customer Usage (MMBTU)	**9,478,000**	**7,183,000**

For the three months ended December 31, 2017, usage at the natural gas distribution systems totaled 9,478,000 MMBTU as compared to 7,183,000 MMBTU during the same period in 2016, an increase of 2,295,000 MMBTU, or 32.0%. The addition of Empire accounted for 1,069,000 MMBTU of the increase. Excluding Empire, usage was 1,226,000 MMBTU, or 17.1%, higher primarily due to increased consumption at the Midstates and Peach State Gas Systems.

Water and Wastewater Distribution Systems

	Three Months Ended December 31	
	2017	**2016**
Average Active Connections For The Period		
Wastewater connections	41,400	41,100
Water distribution connections	111,800	129,400
Total Average Active Connections For The Period	**153,200**	**170,500**
Gallons Provided		
Wastewater treated (millions of gallons)	555	542
Water provided (millions of gallons)	3,909	4,113
Total Gallons Provided	**4,464**	**4,655**

During the three months ended December 31, 2017, the water and wastewater distribution systems provided approximately 3,909 million gallons of water to its customers and treated approximately 555 million gallons of wastewater as compared to 4,113 million gallons of water provided and 542 million gallons of wastewater treated during the same period in 2016. The decrease in the gallons of water provided to customers can be attributed to the disposition of the Mountain Water System in Montana. Excluding the Mountain Water System, the water provided to customers was approximately 289 million gallons, or 7%, higher.

2017 Fourth Quarter Operating Results

	Three Months Ended December 31			
	2017 U.S. $ (millions)	2016 U.S. $ (millions)	2017 Can $ (millions)	2016 Can $ (millions)
Revenue				
Utility electricity sales and distribution	**$ 187.0**	$ 46.9	**$ 237.8**	$ 62.5
Less: cost of sales – electricity	**(51.6)**	(20.6)	**(65.6)**	(27.5)
Net Utility Sales - electricity	**135.4**	26.3	**172.2**	35.0
Utility natural gas sales and distribution	**109.8**	85.1	**140.0**	114.0
Less: cost of sales – natural gas	**(53.1)**	(39.8)	**(67.7)**	(53.2)
Net Utility Sales - natural gas	**56.7**	45.3	**72.3**	60.8
Utility water distribution & wastewater treatment sales and distribution	**31.5**	31.7	**40.1**	42.3
Less: cost of sales – water	**(2.4)**	(2.2)	**(3.1)**	(3.0)
Net Utility Sales - water distribution & wastewater treatment	**29.1**	29.5	**37.0**	39.3
Gas transportation	**9.6**	8.4	**12.3**	10.7
Other revenue	**5.1**	5.0	**6.5**	6.8
Net Utility Sales	**235.9**	114.5	**300.3**	152.6
Operating expenses	**(96.6)**	(50.5)	**(123.1)**	(68.0)
Other income	**1.4**	0.9	**1.8**	1.3
HLBV	**1.3**	—	**1.7**	—
Divisional Operating Profit[1]	**$ 142.0**	$ 64.9	**$ 180.7**	$ 85.9

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

For the three months ended December 31, 2017, the Liberty Utilities Group reported an operating profit (excluding corporate administration expenses) of U.S. $142.0 million as compared to U.S. $64.9 million for the comparable period in the prior year. Measured in Canadian dollars, the Group's operating profit was $180.7 million as compared to $85.9 million during the same period in 2016, which represents an increase of $94.8 million or 110%, excluding corporate administration expenses.

Highlights of the changes are summarized in the following table:

(all dollar amounts in $ millions)		Three Months Ended December 31
Prior Period Operating Profit	**$**	**85.9**
Existing Facilities		
Electricity: Decrease primarily due to retroactive recognition of 12 months of revenue in Q4 of 2016 arising from the 2016 rate case at the Calpeco Electric System.		(6.4)
Gas: Increase primarily due to higher consumption at the Midstates and EnergyNorth Gas Systems.		3.1
Water: Decrease primarily due to lower revenue as a result of the disposition of the Mountain Water System in Montana.		(2.2)
Other: Decrease primarily due to lower contracted services.		(0.1)
		(5.6)
New Facilities		
Electricity: Acquisition of both Empire's electric distribution system ($85.9 million) on January 1, 2017 and the Luning Solar Facility ($4.9 million) on February 15, 2017.		90.8
Gas: Acquisition of Empire's gas distribution system on January 1, 2017.		4.3
Water: Acquisition of Empire's water distribution system on January 1, 2017.		0.3
Other: Acquisition of Empire's fiber optic operations on January 1, 2017.		1.9
		97.3
Rate Cases		
Electricity: Implementation of new rates at the Granite State Electric System.		1.0
Gas: Implementation of new rates at the EnergyNorth, Midstates, New England, and Peach State Gas Systems.		4.1
Water: Implementation of new rates at the Park Water System.		2.0
		7.1
Foreign Exchange		**(4.0)**
Current Period Divisional Operating Profit	**$**	**180.7**

2017 Annual Usage Results

Electric Distribution Systems

	Twelve Months Ended December 31	
	2017	**2016**
Average Active Electric Connections For The Period		
Residential	223,700	80,400
Commercial and industrial	39,200	12,500
Total Average Active Electric Connections For The Period	**262,900**	**92,900**
Customer Usage (GW-hrs)		
Residential	2,320.1	567.0
Commercial and industrial	3,523.1	895.2
Total Customer Usage (GW-hrs)	**5,843.2**	**1,462.2**

For the twelve months ended December 31, 2017, the electric distribution systems' usage totaled 5,843.2 GW-hrs as compared to 1,462.2 GW-hrs for the same period in 2016, an increase of 4,381.0 GW-hrs. The addition of Empire accounted for 4,386.3 GW-hrs of the increase. Excluding Empire, usage was 5.3 GW-hrs, or 0.4%, lower due to decreased usage by commercial customers at the Granite State Electric System.

Natural Gas Distribution Systems

	Twelve Months Ended December 31	
	2017	**2016**
Average Active Natural Gas Connections For The Period		
Residential	287,100	249,000
Commercial and industrial	31,700	26,600
Total Average Active Natural Gas Connections For The Period	**318,800**	**275,600**
Customer Usage (MMBTU)		
Residential	17,621,000	15,346,000
Commercial and industrial	12,672,000	11,361,000
Total Customer Usage (MMBTU)	**30,293,000**	**26,707,000**

For the twelve months ended December 31, 2017, usage at the natural gas distribution systems totaled 30,293,000 MMBTU as compared to 26,707,000 MMBTU during the same period in 2016, an increase of 3,586,000 MMBTU or 13.4%. The addition of Empire accounted for 2,997,000 MMBTU of the increase. Excluding Empire, usage was 589,000 MMBTU, or 2.2%, higher due to increased usage at the EnergyNorth and New England Gas Systems.

Water and Wastewater Distribution Systems

	Twelve Months Ended December 31	
	2017	**2016**
Average Active Connections For The Period		
Wastewater connections	41,000	41,100
Water distribution connections	121,400	131,400
Total Average Active Connections For The Period	**162,400**	172,500
Gallons Provided		
Wastewater treated (millions of gallons)	2,226	2,231
Water provided (millions of gallons)	16,905	17,936
Total Gallons Provided	**19,131**	20,167

During the twelve months ended December 31, 2017, the water and wastewater distribution systems provided approximately 16,905 million gallons of water to its customers and treated approximately 2,226 million gallons of wastewater as compared to 17,936 million gallons of water and 2,231 million gallons of wastewater during the same period in 2016. The decrease in the gallons of water provided to customers can be attributed to the disposition of the Mountain Water System in Montana. Excluding the Mountain Water System, the water provided to customers was approximately 2,295 million gallons, or 14%, higher.

2017 Annual Operating Results

	Twelve Months Ended December 31			
	2017 U.S. $ (millions)	2016 U.S. $ (millions)	2017 Can $ (millions)	2016 Can $ (millions)
Revenue				
Utility electricity sales and distribution	**$ 763.5**	$ 171.7	**$ 989.2**	$ 228.1
Less: cost of sales – electricity	**(222.4)**	(90.0)	**(288.2)**	(119.8)
Net Utility Sales - electricity	**541.1**	81.7	**701.0**	108.3
Utility natural gas sales and distribution	**346.0**	276.8	**450.7**	371.4
Less: cost of sales – natural gas	**(141.7)**	(105.0)	**(184.5)**	(142.1)
Net Utility Sales - natural gas	**204.3**	171.8	**266.2**	229.3
Utility water distribution & wastewater treatment sales and distribution	**140.1**	137.4	**181.9**	181.7
Less: cost of sales – water	**(9.5)**	(9.2)	**(12.3)**	(12.2)
Net Utility Sales - water distribution & wastewater treatment	**130.6**	128.2	**169.6**	169.5
Gas transportation	**31.2**	25.7	**40.7**	34.3
Other revenue	**11.8**	11.0	**15.2**	14.6
Net Utility Sales	**919.0**	418.4	**1,192.7**	556.0
Operating expenses	**(393.7)**	(196.1)	**(512.0)**	(260.6)
Other income	**4.2**	3.9	**5.4**	5.1
HLBV	**6.2**	—	**8.0**	—
Divisional Operating Profit[1]	**$ 535.7**	$ 226.2	**$ 694.1**	$ 300.5

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

For the twelve months ended December 31, 2017, the Liberty Utilities Group reported an operating profit (excluding corporate administration expenses) of U.S. $535.7 million as compared to U.S. $226.2 million for the comparable period in the prior year. Measured in Canadian dollars, the Group's operating profit was $694.1 million as compared to $300.5 million during the same period in 2016, which represents an increase of $393.6 million or 131%, excluding corporate administration expenses.

Highlights of the changes are summarized in the following table:

(all dollar amounts in $ millions)		Twelve Months Ended December 31
Prior Period Operating Profit	$	**300.5**
Existing Facilities		
Gas: Increase primarily due to higher consumption at the EnergyNorth Gas System.		4.5
Water: Decrease primarily due to lower revenue as a result of the disposition of the Mountain Water System in Montana.		(5.3)
Other: Decrease primarily due to lower contracted services.		(3.7)
		(4.5)
New Facilities		
Electricity: Acquisition of both Empire's electric distribution system ($341.4 million) on January 1, 2017 and the Luning Solar Facility ($20.7 million) on February 15, 2017.		362.1
Gas: Acquisition of Empire's gas distribution system on January 1, 2017.		11.9
Water: Acquisition of Empire's water distribution system on January 1, 2017.		1.3
Other: Acquisition of Empire's fiber optic operations on January 1, 2017.		5.7
		381.0
Rate Cases		
Electricity: Implementation of new rates at the Granite State Electric System.		5.2
Gas: Implementation of new rates at the EnergyNorth, Midstates, New England, and Peach State Gas Systems.		12.5
Water: Implementation of new rates at the Park Water, Bella Vista, Rio Rico and Black Mountain Water and Wastewater Systems.		6.1
		23.8
Foreign Exchange		**(6.7)**
Current Period Divisional Operating Profit	$	**694.1**

Regulatory Proceedings

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

Utility	State	Regulatory Proceeding Type	Rate Request U.S. $ (millions)	Current Status
Completed Rate Cases				
Granite State Electric System	New Hampshire	General Rate Case ("GRC")	$7.7	Final Order issued in April 2017 approving a U.S. $6.2 million rate increase effective May 1, 2017, and two additional rate increases of approximately U.S. $0.2 million and U.S. $0.3 million effective May 1, 2018 and May 1, 2019, respectively.
New England Gas	Massachusetts	Gas System Enhancement Plan ("GSEP")	$3.8	Final Order issued in April 2017 approving a U.S. $2.9 million rate increase effective May 1, 2017.
Illinois Gas System	Illinois	GRC	$3.0	Final Order issued in May 2017 approving a U.S. $2.2 million rate increase effective June 7, 2017.
Oklahoma Electricity System	Oklahoma	GRC	$3.0	In August 2017, in lieu of authorizing the proposed rate increase the Oklahoma Corporation Commission ordered an immediate increase of U.S. $1.0 million to capture the return on and of major capital investments related to plant upgrades and authorized Liberty Utilities to return in 2018 to seek the remaining proposed increases.
Calpeco Electric	California	Turquoise Solar Project	$3.0	Final Order issued in December 2017 approving the Settlement Agreement between Liberty Calpeco and the Office of Ratepayer Advocates dated June 30, 2017 which authorizes Liberty Calpeco to acquire, own, and operate the 10 MW, U.S. $15.7 million Turquoise Solar Project.
Calpeco Electric	California	Post-Test Year Adjustment Mechanism	$2.2	Final Order issued in November 2017 approving a U.S $2.2 million rate increase effective January 1, 2018, based on the additional costs related to the Luning Solar Project.
Various	Various	Various	$4.8	Other rate cases closed in 2017 & 2018 with a combined approved rate increase of U.S. $2.8 million include: Entrada Del Oro Water (U.S. $0.2 million), Georgia Gas GRAM (U.S. $0.6 million), New England Gas Decoupling (U.S. $0.2 million), Iowa Gas GRC (U.S. $0.9 million), and Kansas Asbury Environmental and Riverton Cost Recovery Rider (U.S. $0.9 million).

Utility	State	Regulatory Proceeding Type	Rate Request U.S. $ (millions)	Current Status
Pending Rate Cases				
EnergyNorth Gas System	New Hampshire	GRC	$19.7	On April 28, 2017, filed an application seeking an increase of U.S. $13.7 million (updated to U.S. $14.5 million), plus a step increase of U.S. $6.1 million (updated to U.S. $5.2 million) to be implemented in May 2018. Temporary rates of U.S. $7.8 million were requested to be effective as of July 1, 2017, and on June 30, 2017, the New Hampshire Public Utilities Commission ("NH Commission") approved temporary rates of U.S. $6.8 million (87% of the requested amount) effective July 1, 2017 to be in place until the end of the Company's permanent rate case.
Litchfield Park Water & Sewer	Arizona	GRC	$5.1	On February 28, 2017, filed a water/sewer rate application (test year December 31, 2016) seeking a rate increase of U.S. $5.1 million. New rates are expected to be effective in Q4 2018.
Missouri Gas System	Missouri	GRC	$7.5	On September 29, 2017, filed an application seeking a rate increase of U.S. $7.5 million for test year ending June 30, 2017 with proforma adjustments through to March 31, 2018. New rates are expected to be effective in Q3 2018.
Apple Valley Ranchos Water & Park Water Systems	California	GRC	$2.1	On January 2, 2018, filed an application requesting an average rate increase of U.S. $0.7 million and U.S. $1.4 million, respectively and is to set rates for the three year period of 2019 to 2021.
New England Natural Gas System	Massachusetts	GSEP	$6.2	On October 31, 2017, filed the 2018 GSEP application requesting recovery of U.S. $6.2 million (effective May 1, 2018) for replacement of approximately 14 miles of eligible infrastructure.
Various	Various	Various	$4.3	Other pending rate case requests include: Woodmark/Tall Timbers Wastewater Systems (U.S. $1.6 million), Park Water System (U.S. $1.5 million), and Missouri Water System (U.S. $1.2 million).

Completed Rate Cases

On December 14, 2016, the Calpeco Electric System filed an application for approval of the 10 MW Turquoise Solar Project at an estimated cost of U.S. $15.7 million. On June 30, 2017, the Calpeco Electric System and the Office of Ratepayer Advocates filed a joint motion with the Commission requesting approval of its settlement agreement. On December 19, 2017, the Commission issued a decision approving the settlement agreement as filed. The Turquoise Solar Project costs will be included in the Calpeco Electric System's 2019 general rate case and is expected to have a rate impact of approximately U.S. $3.0 million (or 3% increase), which will be offset by future Energy Cost Adjustment Clause ("ECAC)" account reductions. The Turquoise Solar Project is expected to be in service by the fourth quarter of 2018.

On April 29, 2016, the Granite State Electric System filed a rate application seeking a U.S. $5.3 million annual revenue increase proposed for effect July 1, 2016, plus an additional U.S. $2.4 million annual step increase to recover the revenue requirement associated with capital additions made in 2016. The total permanent and step increase proposed was U.S. $7.7 million annually, or a 21.8% increase to distribution revenue. In June 2016, approval of a temporary rate increase of U.S. $2.4 million was issued, effective July 1, 2016. The final permanent rate increase was retroactive to the temporary rate effective date. In April 2017, an order was issued by the New Hampshire Public Utilities Commission ("NHPUC") approving a U.S. $3.8 million rate increase to annual distribution revenues along with an annual increase of U.S. $2.5 million for the revenue requirement associated with 2016 capital investment, both effective May 1, 2017 (achieving 82% of the requested increase). The difference between the U.S. $3.8 million permanent increase and the U.S. $2.4 million temporary rate level that was in effect since July 1, 2016 was collected beginning May 1, 2017. The settlement also provides for two additional annual increases of approximately U.S. $0.2 million and $0.3 million effective May 1, 2018 and May 1, 2019, respectively, to recover the revenue requirement associated with certain significant capital investments made during the prior calendar year.

Pending Regulatory Proceedings

On October 31, 2017, Empire District Electric Company announced a proposed plan to expand its wind resources with the development of up to an additional 800 MW of strategically located wind generation in or near its service territory by the end of 2020. Once fully operational, the project is projected to generate cost savings for customers of U.S. $172.0 million - U.S. $325.0 million over a twenty-year period. Empire filed a request for approval ("Application") of the wind expansion initiative with regulators in Missouri, Kansas, Oklahoma, and Arkansas, and the project is subject to their respective review. On February 6, 2018, the staff of the Missouri Public Service Commission as well as other intervenors filed testimony responsive to the Application. The staff's testimony recommends that the Commission should either approve the projects with conditions or rule that it need not provide approval for the projects to proceed, while other intervenors range in their recommendations from suggesting that the Commission not approve the project to recommending outright approvals. Testimony has now also been received in Oklahoma and Arkansas. In Oklahoma both the staff and the Attorney General recommended approval of the projects and in Arkansas additional details were requested on the proposed projects. The Liberty Utilities Group's local regulatory teams continue to work closely with staffs and commissions from the regulatory agencies and anticipate securing approvals for the projects by June 2018.

CORPORATE DEVELOPMENT ACTIVITIES

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

The development and construction of new power generation facilities involves a number of risks and uncertainties including scheduling delays, cost over runs and other events that may be beyond the control of the Company (See *Operational Risk Management - Development and Construction Risk*).

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

Each of the projects contained in the table below meet the following criteria: a proven wind or solar resource, a signed PPA with a credit-worthy counterparty, and satisfaction of the Company's investment return objectives. The projects are as follows:

Project Name	Location	Size (MW)	Estimated Capital Cost Range (millions)[1]	Commercial Operation	PPA Term (Years)	Production (GW-hrs)
Projects in Construction						
Amherst Island Wind Project	Ontario	75	$ 320 - $ 350	2018	20	235
Great Bay Solar Project[2]	Maryland	75	169 - 188	2018	10	146
Total Projects in Construction		**150**	**$ 489 - $ 538**			**381**
Projects in Development						
Blue Hill Wind Project	Saskatchewan	177	$ 315 - $ 350	2019/20	25	813
Val-Eo Wind Project[3]	Quebec	24	60 - 70	2018	20	66
Turquoise Solar Project[4]	Nevada	10	25 - 31	2018		28
Total Projects in Development		**211**	**$ 400 - $ 451**			**907**
Total in Construction and Development		**361**	**$ 889 - $ 989**			**1,288**

1 Estimated capital costs for U.S. based projects have been converted at the exchange rate in effect at the end of the current reporting period.

2 The total cost of the project is expected to be approximately U.S. $135 - U.S. $150 million. Two of the four Great Bay Solar sites achieved COD in December 2017 while the remaining two sites are expected to achieve COD in the first quarter of 2018.

3 All figures refer solely to Phase I of the Val-Eo Wind Project.

4 The Turquoise Solar Project will be included in the rate base of the Calpeco Electric System (see *Regulatory Proceedings*). The total cost of the project is expected to be approximately U.S. $20.0 - U.S. $25.0 million.

Projects Completed

Deerfield Wind Project

The Deerfield Wind Project is a 150 MW wind powered electric generating development project located in central Michigan and is constructed on approximately 20,000 acres of land leased from a supportive wind power land owner group.

Construction of the project commenced in the fourth quarter of 2015. The project declared commercial operations on February 21, 2017.

The project is the Liberty Power Group's tenth wind generating facility and consists of 44 Vestas V110-2.0 wind turbines and 28 Vestas V110-2.2 turbines and is estimated to generate 555.2 GW-hrs of energy per year, with all energy, capacity, and renewable energy credits from the project sold to a local electric distribution utility which serves 260,000 customers in Michigan, pursuant to a 20 year PPA.

The Liberty Power Group's initial interest in the project was via a 50% joint venture with the original developer along with an option to acquire the other 50% interest. On March 14, 2017, the Liberty Power Group exercised its option and purchased the remaining 50% interest in the project for U.S. $21.6 million.

The project qualified for U.S. federal production tax credits, and consistent with financing structures utilized for U.S. based renewable energy projects, approximately U.S. $166.6 million of financing for the project was received from tax equity investors in May 2017.

Bakersfield II Solar Project

The Bakersfield II Solar Project is a 10 MWac solar powered electric generating project adjacent to the Liberty Power Group's 20 MW Bakersfield I Solar Project in Kern County, California.

Construction of the project commenced in the second quarter of 2015. The facility declared commercial operations on January 11, 2017.

The facility is the Liberty Power Group's third solar generating facility and is comprised of approximately 38,640 solar panels located on 64 acres of land. The project is expected to generate 24.2 GW-hrs of energy per year which is being sold under a 20 year PPA with a large investment grade electric utility.

The project qualified for U.S. federal investment tax credits, and consistent with financing structures utilized for U.S. based renewable energy projects, approximately U.S. $12.3 million of financing for the project was sourced from a tax equity investor. The tax equity financing closed on February 28, 2017, following achievement of commercial operations.

Projects in Construction

Amherst Island Wind Project

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

The project is currently contemplated to use Class III wind turbine generator technology consisting of 26 Siemens 3.0 MW turbines and is expected to produce approximately 235.0 GW-hrs of electrical energy annually, with all energy being sold under a 20 year PPA awarded as part of the Independent Electricity System Operator ("IESO"), formerly the Ontario Power Authority, Feed in Tariff ("FIT") program.

Liberty Power's interest in the project is via a 50% joint venture. Liberty Power has an option to acquire the other 50% interest, subject to certain adjustments, after COD and prior to January 15, 2019.

The total costs to complete the project are estimated at approximately $320.0 million to $350.0 million. The increase in the expected range of construction costs are primarily the result of additional winter construction days than previously anticipated. As the Company refines its operating model for post COD, it has identified new operational costs savings of approximately $10.0 million which are expected to be realized over the life of the project. Construction over the fall and winter months has focused primarily on building access roads, foundations and receiving turbine components.

Manufacturing of major equipment is now complete and turbine deliveries commenced in November 2017, with all turbines expected to be delivered by March 2018. To date, two turbines have been erected and the foundation for the power transformer housing is complete. The main power transformer was delivered to the site in early February 2018. A 115kV submarine cable was also successfully installed during 2017. Subject to receipt of ongoing construction-related permitting, construction is expected to be substantially completed in the second quarter of 2018.

Placement of construction debt closed in the fourth quarter of 2017 with a consortium of major financial institutions for a total commitment of $260.4 million.

Great Bay Solar

The Great Bay Solar Project is a 75 MWac solar powered electric generating development project comprised of four sites located in Somerset County in southern Maryland.

The facility is comprised of 300,000 solar panels and is being constructed on 400 acres of land. The project is expected to generate 146.0 GW-hrs of energy per year, with all energy sold to the U.S. Government Services pursuant to a 10 year PPA, with a 10 year extension option. All Solar Renewable Energy Credits from the project will be retained by the project company and sold into the Maryland market.

The project received its Certificate of Public Convenience and Necessity from the State of Maryland Public Service Commission and building permits from the Somerset County Building and Zoning Department. Both the balance of plant and high voltage engineering, procurement, and construction contracts have been executed.

The total costs to complete the project are estimated at approximately U.S. $135.0 million to U.S. $150.0 million. The project achieved partial completion in late 2017, producing revenue on 25 MW of the full site capacity. Approximately U.S. $59.0 million of the permanent project financing will come from tax equity investors. As of December 31, 2017, the project has received U.S $42.8 million in project funding, with the remaining expected to be received in the first half of 2018.

Projects in Development

Blue Hill Wind Project

The Blue Hill Wind Project is a 177 MW wind powered electric generating development project located in the rural municipalities of Lawtonia and Morse in southwest Saskatchewan.

The project is expected to generate 813.0 GW-hrs of energy per year, with all energy sold to SaskPower pursuant to a 25 year PPA originally awarded in 2012 and amended in 2016.

The project requires development permits as well as final environmental approval. The Environmental Impact Study was completed and submitted to the Saskatchewan Ministry of Environment in the fourth quarter of 2017. Stakeholder engagement continued through 2017 with relevant government officials, NGOs, landowners and the community through open houses and in-person meetings.

The total costs to complete the project are estimated at approximately $315.0 million to $350.0 million. SaskPower recently completed an interim system impact study for the wind turbine generators, which was received in the fourth quarter of 2017. A geotechnical evaluation of the project site and existing infrastructure began in the fourth quarter of 2017, with results expected in early 2018. Preparation and submission of the development permit is expected in the first quarter of 2018.

Val-Éo Wind Project

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

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

The project will be developed in two phases: Phase I of the project is expected to be completed in 2018 and will likely comprise ten 2.35 MW wind turbines for a total capacity of 24 MW and is expected to generate 66.0 GW-hrs of energy per year, with all energy from Phase I of the project to be sold to Hydro-Quebec pursuant to a 20 year PPA; Phase II of the project would entail the development of an additional 101 MW and would be constructed following the successful evaluation of the wind resource at the site, completion of satisfactory permitting and entering into appropriate energy sales arrangements.

The total costs to complete Phase I of the project are estimated at approximately $60.0 million to $70.0 million. All land agreements, construction permits, and authorizations have been obtained for Phase I. The new schedule calls for Phase I construction to begin in the second quarter of 2018, with commissioning to occur in the fourth quarter of 2018.

Turquoise Solar Project

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

The facility is comprised of 108,000 solar thin film panels on a tracker system and is being constructed on 110 acres of land. The Turquoise Solar Project is expected to generate 28 GW-hrs of energy per year and to be included in the rate base of the Calpeco Electric System as energy produced from the project will be consumed by the utility's customers (see *Regulatory Proceedings*).

The project has been approved by the California PUC, and mechanical completion is expected in the fourth quarter of 2018.

The total costs to complete the project are estimated at approximately U.S. $20.0 million to U.S. $25.0 million. The Liberty Utilities Group expects the project will qualify for U.S. federal investment tax credits and accordingly, approximately 30% of the permanent financing is expected to be funded by tax equity investors.

APUC: CORPORATE AND OTHER EXPENSES

	Three Months Ended December 31		Twelve Months Ended December 31	
(all dollar amounts in $ millions)	**2017**	**2016**	**2017**	**2016**
Corporate and other expenses:				
Administrative expenses	**$ 18.7**	$ 13.1	**$ 64.5**	$ 46.3
(Gain)/Loss on foreign exchange	**1.6**	1.3	**0.4**	(0.4)
Interest expense on convertible debentures and acquisition facility related to the Empire Acquisition	**—**	18.2	**17.6**	57.6
Interest expense	**42.4**	20.5	**185.0**	74.0
Interest, dividend, equity, and other income[1]	**(0.6)**	(3.1)	**(2.8)**	(5.3)
Other losses (gains)	**4.7**	(0.8)	**0.6**	(11.8)
Acquisition-related costs	**1.3**	2.4	**62.8**	12.0
Loss (gain) on derivative financial instruments	**(4.0)**	(12.9)	**(2.6)**	(15.8)
Income tax expense	**38.0**	11.5	**95.2**	37.1

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

U.S. Tax Reform

On December 22, 2017, H.R. 1, the Tax Cuts and Jobs Act ("U.S. Tax Reform" or the "Act"), was signed into law which resulted in significant changes to U.S. tax law. Key provisions of U.S. Tax Reform include the following:

- U.S. federal corporate income tax rate reduction from 35 per cent to 21 per cent effective January 1, 2018.
- The corporate alternative minimum tax ("AMT") is eliminated effective January 1, 2018.
- The Base Erosion Anti-Abuse Tax ("BEAT") is a new minimum tax computed each year and is generally the excess of (a) 10% of the taxpayer's "modified taxable income" over (b) the taxpayer's regular tax liability reduced by its tax credits.
- Other than for regulated utilities, interest deductibility is limited to 30 per cent of EBITDA from 2018 to 2021 and 30 per cent of EBIT after 2021.
- Other than for regulated utilities, immediate expensing of 100 per cent of the cost of new investments made in qualified depreciable assets after September 27, 2017.
- The production tax credit (the "PTC") of Section 45 of the Code and the investment tax credit (the "ITC") of Section 48 of the Code are left unchanged by the Act and the elimination of the AMT ensures that renewable energy tax credits will continue to be valuable to tax equity investors.
- The Act allows taxpayers until 2025 to offset any tax owed under the BEAT by 80% of the value of the PTCs and the ITCs for renewable energy projects.
- No change was made to the "continuous construction" requirement for determining when construction of a project commences.

As a result of these changes, the Company has remeasured existing deferred income tax assets and deferred income tax liabilities related to our U.S. regulated and non-regulated businesses to reflect the new lower income tax rate as at December 31, 2017. This remeasurement resulted in a one-time non-cash accounting charge of $22.4 million and is recorded in the Company's 2017 consolidated statement of operations.

Future Impacts

Beginning in 2018, the Company expects its effective tax rate on consolidated worldwide net income to be below 20%.

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

The Company believes that most of its U.S. holding company interest can be properly allocable in accordance with the Act to its U.S. regulated utilities and is therefore largely exempted from the interest deductibility limitations.

It is expected there will be no material changes to the Company's U.S. regulated utilities' future net earnings, specifically as it pertains to U.S. Tax Reform since normal rate making processes would see the lower income tax expense and amortization of the deferred tax revaluation regulatory liability offset by lower customer rates over time. However, the Company believes that all stakeholders are best served by dealing with U.S. Tax Reform within the context of a full regulatory rate case proceeding, where all factors that comprise rates can be considered including investments in rate base, recovery of operating costs, capital structure and cost of capital.

APUC views that going forward the lower tax rates can enable accelerated investment over time in our regulated utilities to deliver an improved customer experience and more reliable service with less of an impact on customer rates than would otherwise occur.

APUC continues to believe that with the provisions in the Act for PTCs and ITCs, between the Company's ability to absorb a part of the renewable energy tax credits in future years and anticipated future demand from third party tax equity investors wishing to avail themselves of renewable energy tax credits, the Company will be able to satisfy the tax equity financing component for its U.S. renewable energy projects over the next three to five years.

SEC Guidance

The U.S. Securities and Exchange Commission ("SEC") has issued guidance allowing registrants to record provisional amounts which may be adjusted as information over time becomes available, prepared or analyzed during a measurement period not to exceed one year.

The SEC guidance summarizes a three-step process to be applied at each reporting period to identify: (1) where the accounting is complete; (2) provisional amounts where the accounting is not yet complete, but a reasonable estimate has been determined; and (3) where a reasonable estimate cannot yet be determined and therefore income taxes are reflected in accordance with tax laws in effect prior to the enactment of the Act.

At December 31, 2017, APUC considers all amounts recorded related to U.S. Tax Reform to be reasonable estimates. Given that APUC's utility businesses are regulated, the Company's interpretation, assessment and presentation of the impact of U.S. Tax Reform may be further clarified with additional guidance from regulatory, tax and accounting authorities. Should additional information emerge that affects current estimates during this one-year measurement period allowed for by the SEC, adjustments will be made to the provisional amounts as appropriate.

2017 Fourth Quarter Corporate and Other Expenses

During the three months ended December 31, 2017, administrative expenses totaled $18.7 million as compared to $13.1 million in the same period in 2016. The $5.6 million increase primarily relates to additional costs incurred to administer APUC's operations as a result of the Company's growth, including ongoing administration expenses related to Empire.

For the three months ended December 31, 2017, interest expense on convertible debentures and bridge financing totaled $nil as compared to $18.2 million in the same period in 2016.

For the three months ended December 31, 2017, interest expense totaled $42.4 million as compared to $20.5 million in the same period in 2016. The interest expense for the period is primarily attributable to assumed and incremental debt related to the Empire Acquisition, and new debt raised by the Liberty Power and Liberty Utilities Groups.

For the three months ended December 31, 2017, other losses were $4.7 million as compared to gains of $0.8 million in the same period in 2016. The increase in current period losses is primarily attributable to an increase in regulatory liabilities in the LPSCo Water System resulting from ongoing regulatory proceedings.

For the three months ended December 31, 2017, gains on derivative financial instruments totaled $4.0 million as compared to $12.9 million in the same period in 2016. The increase in 2016 was primarily driven by mark-to-market gains on foreign currency derivatives.

For the three months ended December 31, 2017, an income tax expense of $38.0 million was recorded as compared to an income tax expense of $11.5 million during the same period in 2016. The increase in income tax expense is primarily due to the Empire Acquisition and a one-time non-cash accounting charge of $22.4 million related to the revaluation of the Company's U.S. non-regulated net deferred income tax assets as a result of U.S. Tax Reform (see *U.S. Tax Reform* for additional information).

2017 Annual Corporate and Other Expenses

During the twelve months ended December 31, 2017, administrative expenses totaled $64.5 million as compared to $46.3 million in the same period in 2016. The increase primarily relates to additional costs incurred to administer APUC's operations as a result of the Company's growth, including ongoing administration expenses related to Empire.

For the twelve months ended December 31, 2017, interest expense on convertible debentures and bridge financing totaled $17.6 million as compared to $57.6 million in the same period in 2016 (see *note 14* in the financial statements).

For the twelve months ended December 31, 2017, interest expense totaled $185.0 million as compared to $74.0 million in the same period in 2016. The increase in interest expense for the period is primarily attributable to assumed and incremental debt related to the Empire Acquisition, and new debt raised by the Liberty Power and Liberty Utilities Groups. (See *Credit Facilities & Debt* and *note 9* in the financial statements).

For the twelve months ended December 31, 2017, other losses were $0.6 million as compared to a gain of $11.8 million in the same period in 2016. The prior period gains primarily resulted from: (i) the recognition of deferred income on repairs completed for facilities where the insurance proceeds have been received in advance; and (ii) the settlement of litigation and bankruptcy proceedings relating to Trafalgar Power Inc. (see *note 18* in the financial statements) partially offset by (iii) the write-down of the Company's equity interest in natural gas development projects that have been canceled by the developer.

For the twelve months ended December 31, 2017, acquisition-related costs totaled $62.8 million as compared to $12.0 million in the same period in 2016. The increase is primarily attributable to the Empire Acquisition.

For the twelve months ended December 31, 2017, the gain on derivative financial instruments totaled $2.6 million as compared to a gain of $15.8 million in the same period in 2016. The gain in 2016 was due to market-to-market gains on foreign currency hedges offset by losses on the ineffective portion of derivative financial instruments accounted for as derivatives.

An income tax expense of $95.2 million was recorded in the twelve months ended December 31, 2017 as compared to an income tax expense of $37.1 million during the same period in 2016. The increase in income tax expense is primarily due to the Empire Acquisition, the tax effect related to the Mountain Water condemnation, and a one-time non-cash accounting charge of $22.4 million related to the revaluation of the Company's U.S. non-regulated net deferred income tax assets as a result of U.S. Tax Reform (see *U.S. Tax Reform* for additional information).

NON-GAAP FINANCIAL MEASURES

Reconciliation of Adjusted EBITDA to Net Earnings

The following table is derived from and should be read in conjunction with the consolidated statement of operations. This supplementary disclosure is intended to more fully explain disclosures related to Adjusted EBITDA and provides additional information related to the operating performance of APUC. Investors are cautioned that this measure should not be construed as an alternative to U.S. GAAP consolidated net earnings.

	Three Months Ended December 31		Twelve Months Ended December 31	
(all dollar amounts in $ millions)	**2017**	**2016**	**2017**	**2016**
Net earnings attributable to shareholders	**$ 60.0**	$ 46.3	**$ 193.1**	$ 130.9
Add (deduct):				
Net earnings attributable to the non-controlling interest, exclusive of HLBV	**0.8**	(0.8)	**3.2**	7.5
Income tax expense	**38.0**	11.5	**95.2**	37.1
Interest expense on convertible debentures and bridge financing	**—**	18.2	**17.6**	57.6
Interest expense on long-term debt and others	**42.4**	20.5	**185.0**	74.0
Other losses (gains)	**4.8**	(0.8)	**0.7**	(11.9)
Acquisition-related costs	**1.3**	2.4	**62.8**	12.0
Costs related to tax equity financing	**0.5**	—	**2.3**	—
Loss (gain) on derivative financial instruments	**(4.0)**	(12.9)	**(2.6)**	(15.8)
Realized loss on energy derivative contracts	**—**	—	**(0.7)**	(1.0)
Loss (gain) on foreign exchange	**1.6**	1.3	**0.4**	(0.4)
Depreciation and amortization	**88.0**	52.6	**326.4**	186.9
Adjusted EBITDA	**$ 233.4**	$ 138.3	**$ 883.4**	$ 476.9

HLBV represents the value of net tax attributes earned during the period primarily from electricity generated by certain U.S. wind power and U.S. solar generation facilities. HLBV earned in the three and twelve months ended December 31, 2017 amounted to $14.3 million and $67.8 million as compared to $13.6 million and $41.0 million during the same period in 2016.

Reconciliation of Adjusted Net Earnings to Net Earnings

The following table is derived from and should be read in conjunction with the consolidated statement of operations. This supplementary disclosure is intended to more fully explain disclosures related to Adjusted Net Earnings and provides additional information related to the operating performance of APUC. Investors are cautioned that this measure should not be construed as an alternative to consolidated net earnings in accordance with U.S. GAAP.

The following table shows the reconciliation of net earnings to Adjusted Net Earnings exclusive of these items:

	Three Months Ended December 31		Twelve Months Ended December 31	
(all dollar amounts in $ millions)	2017	2016	2017	2016
Net earnings attributable to shareholders	**$ 60.0**	$ 46.3	**$ 193.1**	$ 130.9
Add (deduct):				
Loss (gain) on derivative financial instruments	**(4.0)**	(12.9)	**(2.6)**	(15.8)
Realized loss on derivative financial instruments	**—**	—	**(0.7)**	(1.0)
Loss (gain) on long-lived assets, net	**1.5**	(0.8)	**(2.5)**	(3.3)
Loss (gain) on foreign exchange	**1.6**	1.3	**0.4**	(0.4)
Interest expense on convertible debentures and acquisition financing	**—**	18.2	**17.6**	57.6
Acquisition-related costs	**1.3**	2.4	**62.8**	12.0
Costs related to tax equity financing	**0.5**	—	**2.3**	—
Other adjustments	**3.2**	—	**3.2**	—
U.S. Tax Reform adjustment [2]	**22.4**		**22.4**	
Adjustment for taxes related to above	**(0.6)**	(3.1)	**(3.9)**	(18.4)
Adjusted Net Earnings	**$ 85.9**	$ 51.4	**$ 292.1**	$ 161.6
Adjusted Net Earnings per share[1]	**$ 0.20**	$ 0.18	**$ 0.74**	$ 0.57

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

[2] Represents the one-time non-cash accounting charge related to the revaluation of U.S. non-regulated net deferred income tax assets as a result of U.S. Tax Reform (see *U.S. Tax Reform* for additional information).

For the three months ended December 31, 2017, Adjusted Net Earnings totaled $85.9 million as compared to Adjusted Net Earnings of $51.4 million for the same period in 2016, an increase of $34.5 million. The increase in Adjusted Net Earnings for the three months ended December 31, 2017 is primarily due to increased earnings from operations partially offset by higher depreciation and amortization expense as compared to 2016.

For the twelve months ended December 31, 2017, Adjusted Net Earnings totaled $292.1 million as compared to Adjusted Net Earnings of $161.6 million for the same period in 2016, an increase of $130.5 million. The increase in Adjusted Net Earnings for the twelve months ended December 31, 2017 is primarily due to increased earnings from operations partially offset by higher depreciation and amortization expense as compared to 2016.

Reconciliation of Adjusted Funds from Operations to Cash Flows from Operating Activities

The following table is derived from and should be read in conjunction with the consolidated statement of operations and consolidated statement of cash flows. This supplementary disclosure is intended to more fully explain disclosures related to Adjusted Funds from Operations and provides additional information related to the operating performance of APUC. Investors are cautioned that this measure should not be construed as an alternative to funds from operations in accordance with U.S GAAP.

The following table shows the reconciliation of funds from operations to Adjusted Funds from Operations exclusive of these items:

	Three Months Ended December 31		Twelve Months Ended December 31	
(all dollar amounts in $ millions)	2017	2016	2017	2016
Cash flows from operating activities	**$ 169.8**	$ 121.9	**$ 457.8**	$ 287.9
Add (deduct):				
Changes in non-cash operating items	**(12.0)**	(46.7)	**74.0**	(3.7)
Production based cash contributions from non-controlling interests	**—**	0.6	**10.6**	11.2
Interest expense on convertible debentures and acquisition financing fees[1]	**—**	18.2	**9.3**	57.6
Acquisition-related costs	**1.3**	2.4	**62.8**	12.0
Cash generated from sale of long-lived assets	**—**	—	**—**	(8.6)
Adjusted Funds from Operations	**$ 159.1**	$ 96.4	**$ 614.5**	$ 356.4

[1] Exclusive of deferred financing fees of $8.3 million.

For the three months ended December 31, 2017, Adjusted Funds from Operations totaled $159.1 million as compared to Adjusted Funds from Operations of $96.4 million for the same period in 2016, an increase of $62.7 million.

For the twelve months ended December 31, 2017, Adjusted Funds from Operations totaled $614.5 million as compared to Adjusted Funds from Operations of $356.4 million for the same period in 2016, an increase of $258.1 million.

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

	Three Months Ended December 31		Twelve Months Ended December 31	
(all dollar amounts in $ millions)	2017	2016	2017	2016
Liberty Power Group:				
Maintenance	**$ 4.0**	$ 21.0	**$ 18.1**	$ 58.6
Investment in Capital Projects[1]	**17.1**	169.0	**592.7**	538.1
	$ 21.1	$ 190.0	**$ 610.8**	$ 596.7
Liberty Utilities Group:				
Rate Base Maintenance	**$ 58.4**	$ 27.0	**$ 222.1**	$ 102.7
Rate Base Acquisition	**—**	—	**2,764.4**	345.3
Rate Base Growth	**89.8**	101.0	**328.7**	163.4
	148.2	128.0	**3,315.2**	611.4
Total Capital Expenditures	**$ 169.3**	$ 318.0	**$ 3,926.0**	$ 1,208.1

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

2017 Fourth Quarter Property Plant and Equipment Expenditures

During the three months ended December 31, 2017, the Liberty Power Group incurred capital expenditures of $21.1 million as compared to $190.0 million during the same period in 2016. The capital expenditures include the ongoing construction of the Great Bay Solar Project, additional investment into the Amherst Wind Project, and ongoing maintenance capital at existing operating sites. Capital expenditures in the same quarter last year included the purchase of approximately $75 million of turbine components ("Safe Harbor Turbines"), costs of rebuilding the Donnaconna Hydro Facility dam, and ongoing development costs related to the investment and build of the Deerfield Wind, Amherst Wind, and Great Bay Solar Projects.

During the three months ended December 31, 2017, the Liberty Utilities Group invested $148.2 million in capital expenditures as compared to $128.0 million during the same period in 2016. The Liberty Utilities Group's investment was primarily related to reliability enhancements, improvements and replenishment opportunities, and leak prone pipe replacements, leak repairs and pipeline corrosion protection initiatives relating to safety and reliability at the electric and gas systems. Capital expenditures in the same quarter last year included investments into the Luning Solar Facility and further development of Phase I of the North Lake Tahoe transmission project to upgrade the 650 Line (10 miles) which runs from Northstar to Kings Beach, California to 120kV.

2017 Annual Property Plant and Equipment Expenditures

During the twelve months ended December 31, 2017, the Liberty Power Group incurred capital expenditures of $610.8 million as compared to $596.7 million during the same period in 2016. The capital expenditures include the acquisition of the remaining outstanding interest in the Deerfield Wind Facility, completion of the Bakersfield II Solar Facility, upgrade of the Tinker Transmission Facility, and ongoing development costs related to the investment and construction of the Amherst Wind and Great Bay Solar Projects.

During the twelve months ended December 31, 2017, the Liberty Utilities Group invested $3.3 billion in capital expenditures as compared to $611.4 million during the same period in 2016. The increase in capital expenditures is primarily due to the Empire Acquisition in January 2017 (U.S. $2.4 billion) and completion of the Luning Solar Facility located in Mineral County, Nevada in February 2017 (U.S. $84.9 million). In the prior year, the Liberty Utilities Group completed the acquisition of the Park Water System in January 2016, further development of Phase I of the North Lake Tahoe transmission project, and reliability enhancements, improvements and replenishment opportunities at the utility systems served.

2018 Capital Investments

In 2018, the Company plans to spend between $1.2 billion and $1.4 billion on capital investment opportunities. Actual expenditures during the course of 2018 may vary due to timing of various project investments and the realized U.S. dollar exchange rate.

Expected 2018 capital investment ranges are as follows:

(all dollar amounts in $ millions)			
Liberty Power Group:			
Maintenance	$ 30.0	-	$ 40.0
Investment in Capital Projects	120.0	-	150.0
Total Liberty Power Group:	$ 150.0	-	$ 190.0
Liberty Utilities Group:			
Rate Base Maintenance	$ 210.0	-	$ 230.0
Rate Base Growth	140.0	-	180.0
Total Liberty Utilities Group:	$ 350.0	-	$ 410.0
Investment in Atlantica[1]	$ 700.0		$ 800.0
Total 2018 Capital Investments	**$ 1,200.0**	**-**	**$ 1,400.0**

[1] See *Major Highlights*

The Liberty Power Group intends to spend between $150.0 million - $190.0 million over the course of 2018 to develop or further invest in capital projects, primarily in relation to the final development of the Great Bay Solar and Amherst Island Wind Projects. Additionally, the Liberty Power Group plans to spend $30.0 million - $40.0 million on various operational solar, thermal, and wind assets to maintain safety, regulatory, and operational efficiencies.

The Liberty Utilities Group intends to spend between $350.0 million - $410.0 million over the course of 2018 in an effort to improve the reliability of the utility systems and broaden the technologies used to better serve its service areas. Projects entail spending capital for structural improvements, specifically in relation to drilling and equipping aquifers, main replacements, and reservoir pumping stations.

LIQUIDITY AND CAPITAL RESERVES

APUC has revolving credit and letter of credit facilities available for Corporate, the Liberty Power Group, and the Liberty Utilities Group to manage the liquidity and working capital requirements of each division (collectively the "Bank Credit Facilities").

Bank Credit Facilities

The following table sets out the Bank Credit Facilities available to APUC and its operating groups as at December 31, 2017:

	As at December 31, 2017				As at Dec 31, 2016
(all dollar amounts in $ millions)	**Corporate**	**Liberty Power**	**Liberty Utilities**	**Total**	**Total**
Committed facilities	$ 165.0	$ 714.9	$ 501.8	**$ 1,381.7**	$ 773.8
Funds drawn on facilities	—	(44.8)	(16.3)	**(61.1)**	(242.9)
Letters of credit issued	(13.9)	(136.3)	(24.5)	**(174.7)**	(234.9)
Liquidity available under the facilities	**151.1**	**533.8**	**461.0**	**1,145.9**	296.0
Cash on hand				**54.6**	110.4
Total Liquidity and Capital Reserves	**$ 151.1**	**$ 533.8**	**$ 461.0**	**$ 1,200.5**	$ 406.4

As at December 31, 2017, the Company's $165.0 million senior unsecured revolving credit facility (the "Corporate Credit Facility") was undrawn and had $13.9 million of outstanding letters of credit. The facility matures on November 19, 2018 and is subject to customary covenants.

On December 21, 2017, the Company entered into a U.S. $600.0 million term credit facility with two Canadian banks maturing on December 21, 2018. The proceeds of the term credit facility provide the company with additional liquidity for general corporate purposes and acquisitions. On March 7, 2018 the company drew U.S. $600.0 million under this facility.

As at December 31, 2017, the Liberty Power Group's committed bank lines consisted of a U.S. $500.0 million senior unsecured syndicated revolving credit facility and a $87.6 million letter of credit facility (Cdn $50.0 million and U.S. $30.0 million). As at December 31, 2017, the group had drawn $44.8 million and had $136.3 million in outstanding letters of credit. The facilities mature on October 6, 2022 and October 30, 2018, respectively. Subsequent to year-end, on February 16, 2018, the Liberty Power Group increased availability under its revolving letter of credit facility to U.S. $200.0 million and extended the maturity to January 31, 2021. The expansion of both the revolving credit and letter of credit facility further increases the Liberty Power Group's ability to support the cash needs of its development portfolio.

As at December 31, 2017, the Liberty Utilities Group's committed bank lines consisted of a U.S. $200.0 million senior unsecured syndicated revolving credit facility at the holding company ("Liberty Credit Facility") and a U.S. $200.0 million revolving credit facility at Empire ("Empire Credit Facility"). The credit facilities mature on September 30, 2018 and October 20, 2019, respectively. The Empire Credit Facility is used primarily as a backstop to commercial paper issued by Empire. As at December 31, 2017, the Liberty Utilities Group had drawn a total of $16.3 million (U.S. $13.0 million) and had $24.5 million (U.S. $19.5 million) of outstanding letters of credit. Subsequent to year-end on February 23, 2018, the Liberty Utilities Group increased commitments under the Liberty Credit Facility to U.S. $500.0 million and extended the maturity to 2023. In conjunction with the increase to the Liberty Credit Facility, the Empire Credit Facility was canceled. The Liberty Credit Facility will now be used as a backstop for Empire's commercial paper program and as a source of liquidity for Empire as required.

On February 9, 2016, in connection with the Empire Acquisition, the Company obtained U.S. $1.6 billion in acquisition financing commitments ("Acquisition Facility") from a syndicate of banks. On December 30, 2016, the Company drew U.S. $1,336.4 million on the Acquisition Facility in connection with the closing of the Empire Acquisition. The Acquisition Facility was fully repaid in the first quarter of 2017 from proceeds received from the final installment payment, the Liberty Private Placement (discussed below) and general corporate funds.

Long Term Debt

On January 17, 2017, the Liberty Power Group issued $300.0 million of senior unsecured debentures bearing interest at 4.09% with a maturity date of February 17, 2027. The debentures were sold at a price of $99.929 per $100.00 principal amount. Concurrent with the offering, the Liberty Power Group entered into a cross currency swap, coterminous with the debentures, to economically convert the Canadian dollar denominated offering into U.S. dollars for an effective yield of 4.86%.

On March 24, 2017, the Liberty Utilities Group's financing entity issued U.S. $750.0 million of senior unsecured notes ("Liberty Private Placement") in the U.S. and Canada. The notes are of varying maturities from 3 to 30 years with a weighted average life of approximately 15 years and a weighted average coupon of 4.0%. In anticipation of the financing, Liberty Utilities had entered into forward contracts to lock in the underlying U.S. Treasury interest rates (see "*Interest Rate Risk*"). Considering the effect of the hedges, the effective weighted average rate paid by the Liberty Utilities Group is 3.6%. The proceeds of the offering were applied to repay the balance of the Acquisition Facility and other existing indebtedness.

As at December 31, 2017, the weighted average tenor of APUC's total long term debt is approximately 12 years with an average interest rate of 4.6%.

Convertible Unsecured Subordinated Debentures

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

All Debentures were sold on an instalment basis at a price of $1,000 dollars per debenture, of which $333 dollars was paid on the closing of the Offering and the remaining $667 dollars was payable on a date set by APUC upon satisfaction of all conditions precedent to the closing of the Empire Acquisition (the "Final Instalment Date"), at which time each debenture was convertible to 94.3396 common shares of APUC and bears an interest rate of 0% thereafter.

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

Credit Ratings

APUC has a long term consolidated corporate credit rating of BBB (flat) from Standard & Poor's ("S&P") and a BBB (low) rating from DBRS Limited ("DBRS"). Algonquin Power Co ("APCo"), the parent company for the Liberty Power Group, has a BBB (flat) issuer rating from S&P and BBB (low) issuer rating from DBRS. Liberty Utilities Finance GP1 ("Liberty Finance"), a special purpose financing entity of Liberty Utilities Co., the parent company for the Liberty Utilities Group, has a BBB (high) issuer rating from DBRS. Empire has a BBB rating from S&P and a Baa1 rating from Moody's Investors Service, Inc. ("Moody's").

Contractual Obligations

Information concerning contractual obligations as of December 31, 2017 is shown below:

(all dollar amounts in $ millions)	Total	Due less than 1 year	Due 1 to 3 years	Due 4 to 5 years	Due after 5 years
Principal repayments on debt obligations[1]	**$ 3,826.1**	$ 279.7	$ 570.1	$ 645.0	$ 2,331.3
Convertible debentures	**1.2**	—	—	—	1.2
Advances in aid of construction	**78.6**	1.5	—	—	77.1
Interest on long-term debt obligations	**2,006.2**	172.7	307.5	250.8	1,275.2
Purchase obligations	**501.9**	501.9	—	—	—
Environmental obligations	**72.0**	7.8	18.9	5.4	39.9
Derivative financial instruments:					
Cross currency swap	**72.0**	4.4	8.1	64.7	(5.2)
Interest rate swap	**10.6**	10.6	—	—	—
Currency forward	**0.4**	0.4	—	—	—
Energy derivative and commodity contracts	**3.4**	2.3	1.0	—	0.1
Purchased power	**527.4**	74.0	98.3	100.7	254.4
Gas delivery, service and supply agreements	**369.2**	91.4	118.7	61.6	97.5
Service agreements	**673.9**	47.7	95.7	95.4	435.1
Capital projects	**58.3**	41.1	17.1	0.1	—
Operating leases	**270.0**	9.6	17.3	18.1	225.0
Other obligations	**155.3**	45.0	—	—	110.3
Total Obligations	**$ 8,626.5**	**$ 1,290.1**	**$ 1,252.7**	**$ 1,241.8**	**$ 4,841.9**

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

Equity

The common shares of APUC are publicly traded on the Toronto Stock Exchange (“TSX”) and the New York Stock Exchange ("NYSE") under the trading symbol "AQN". As at December 31, 2017, APUC had 431,765,935 issued and outstanding common shares.

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

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

Net proceeds of the offering are expected to be used, in part, to finance APUC's acquisition of a 25% ownership stake in Atlantica from Abengoa and for general corporate purposes.

APUC is also authorized to issue an unlimited number of preferred shares, issuable in one or more series, containing terms and conditions as approved by the Board. As at December 31, 2017, APUC had outstanding:

- 4,800,000 cumulative rate reset Series A preferred shares, yielding 4.5% annually for the initial six-year period ending on December 31, 2018;
- 100 Series C preferred shares that were issued in exchange for 100 Class B limited partnership units by St. Leon Wind Energy LP; and
- 4,000,000 cumulative rate reset Series D preferred shares, yielding 5.0% annually for the initial five year period ending on March 31, 2019.

APUC has a shareholder dividend reinvestment plan (the “Reinvestment Plan”) for registered holders of common shares of APUC. As at December 31, 2017, 94,049,616 common shares representing approximately 22% of total common shares outstanding had been registered with the Reinvestment Plan. During the year ended December 31, 2017, 3,905,848 common shares were issued under the Reinvestment Plan, and subsequent to year-end, on January 12, 2018, an additional 1,063,572 common shares were issued under the Reinvestment Plan.

SHARE-BASED COMPENSATION PLANS

For the twelve months ended December 31, 2017, APUC recorded $10.8 million in total share-based compensation expense as compared to $5.7 million for the same period in 2016. There is no tax benefit associated with the share-based compensation expense. The compensation expense is recorded as part of administrative expenses in the consolidated statement of operations. The portion of share-based compensation costs capitalized as cost of construction is insignificant.

As at December 31, 2017, total unrecognized compensation costs related to non-vested options and share unit awards were $2.8 million and $8.5 million, respectively, and are expected to be recognized over a period of 1.61 and 1.84 years, respectively.

Stock Option Plan

APUC has a stock option plan that permits the grant of share options to key officers, directors, employees and selected service providers. Except in certain circumstances, the term of an option shall not exceed ten (10) years from the date of the grant of the option.

APUC determines the fair value of options granted using the Black-Scholes option-pricing model. The estimated fair value of options, including the effect of estimated forfeitures, is recognized as expense on a straight-line basis over the options' vesting periods while ensuring that the cumulative amount of compensation cost recognized at least equals the value of the vested portion of the award at that date. During the twelve months ended December 31, 2017, the Company granted 2,328,343 options to executives of the Company. The options allow for the purchase of common shares at a weighted average price of $12.82, the market price of the underlying common share at the date of grant. In March 2017, executives of the Company exercised 1,469,362 stock options at a weighted average exercise price of $7.81 in exchange for common shares issued from treasury and 165,139 options were settled at their cash value as payment for tax withholdings related to the exercise of the options.

As at December 31, 2017, a total of 6,738,856 options are issued and outstanding under the stock option plan.

Performance Share Units

APUC issues performance share units ("PSUs") to certain members of management as part of APUC's long-term incentive program. During the twelve months ended December 31, 2017, the Company granted (including dividends and performance adjustments) 811,974 PSUs to executives and employees of the Company. During the year, the Company settled 374,973 PSUs, of which 183,035 PSUs were exchanged for common shares issued from treasury and 191,938 PSUs were settled at their cash value as payment for tax withholdings related to the settlement of the PSUs. Additionally, during 2017, a total of 60,961 PSUs were forfeited.

As at December 31, 2017, a total of 955,028 PSUs are granted and outstanding under the PSU plan.

Directors Deferred Share Units

APUC has a Directors' Deferred Share Unit Plan. Under the plan, non-employee directors of APUC receive 50% of their annual compensation in deferred share units ("DSUs") and may elect to receive any portion of their remaining compensation in DSUs. The DSUs provide for settlement in cash or shares at the election of APUC. As APUC does not expect to settle the DSUs in cash, these DSUs are accounted for as equity awards. During the twelve months ended December 31, 2017, the Company issued 69,243 DSUs (including DSUs in lieu of dividends) to the directors of the Company.

As at December 31, 2017, a total of 293,906 DSUs had been granted under the DSU plan.

Employee Share Purchase Plan

APUC has an Employee Share Purchase Plan (the "ESPP") which allows eligible employees to use a portion of their earnings to purchase common shares of APUC. The aggregate number of shares reserved for issuance from treasury by APUC under this plan shall not exceed 2,000,000 shares. During the twelve months ended December 31, 2017, the Company issued 283,523 common shares to employees under the ESPP.

As at December 31, 2017, a total of 779,553 shares had been issued under the ESPP.

MANAGEMENT OF CAPITAL STRUCTURE

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

APUC's objectives when managing capital are:

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

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

RELATED PARTY TRANSACTIONS

Emera Inc.

An executive at Emera Inc. ("Emera") was a member of the Board of APUC until June 8, 2017. The Energy Services Business sold electricity to Maine Public Service Company, and Bangor Hydro, both of which are subsidiaries of Emera. The portion considered related party transactions during 2017 amounts to U.S. $4.4 million as compared to U.S. $10.2 million during the same period in 2016. The Liberty Utilities Group purchased natural gas from Emera for its gas utility customers. The portion considered related party transactions during 2017 amounts to U.S. $1.0 million as compared to U.S. $3.9 million during the same period in 2016. Both the sale of electricity to Emera and the purchase of natural gas from Emera followed a public tender process, the results of which were approved by the regulator in the relevant jurisdiction.

In 2016, a subsidiary of the Company and Emera Utility Services Inc. entered into a design, engineering, supply, and construction agreement for the Tinker transmission upgrade project. The transmission upgrade was placed in service in the second quarter of 2017, with the final completion of the contract work in the fourth quarter of 2017. The total cost of the contract was $9.5 million. The contract followed a market based request for proposal process. On October 14, 2016, APUC paid $0.7 million to Emera as reimbursement for professional services incurred and accrued in 2014.

There was U.S. $1.5 million included in accruals in 2017 as compared to U.S. $0.8 million during the same period in 2016 related to these transactions.

Equity-method investments

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

Trafalgar

In 2016, the Company received U.S. $10.1 million in proceeds from the settlement of the Trafalgar matter and paid U.S. $2.9 million to an entity partially and indirectly owned by Senior Executives as its proportionate share. The gain to APUC, net of legal and other liabilities, of approximately U.S. $6.6 million was recorded in 2016.

Long Sault Hydro Facility

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

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

ENTERPRISE RISK MANAGEMENT

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

An enterprise risk management, or "ERM", framework is embedded across the organization that systematically and broadly identifies, assesses, and mitigates the key strategic, operational, financial, and compliance risks that may impact the achievement of the Corporation's current objectives, as well as those inherent to strategic alternatives available to the Corporation. The Corporation's ERM policy details the risk management processes, risk appetite, and risk governance structure which clearly establishes accountabilities for managing risk across the organization.

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

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

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

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

The risks discussed below are not intended as a complete list of all exposures that APUC is encountering or may encounter. A further assessment of APUC and its subsidiaries' business risks is set out in the Company's most recent AIF available on SEDAR.

Treasury Risk Management

Downgrade in the Company's Credit Rating Risk

APUC has a long term consolidated corporate credit rating of BBB (flat) from S&P and a BBB (low) rating from DBRS. Algonquin Power Co ("APCo"), the parent company for the Liberty Power Group, has a BBB (flat) issuer rating from S&P and BBB (low) issuer rating from DBRS. Liberty Utilities Finance GP1 ("Liberty Finance"), a special purpose financing entity of Liberty Utilities Co., the parent company for the Liberty Utilities Group, has a BBB (high) issuer rating from DBRS. Empire has a BBB rating from S&P and a Baa1 rating from Moody's.

The ratings indicate the agencies' assessment of APUC's ability to pay the interest and principal of debt securities it issues. A rating is not a recommendation to purchase, sell or hold securities and each rating should be evaluated independently of any other rating. The lower the rating, the higher the interest cost of the securities when they are sold. A downgrade in APUC's or its subsidiaries' issuer corporate credit ratings would result in an increase in APUC's borrowing costs under its bank credit facilities and future long-term debt securities issued. If any of APUC's ratings fall below investment grade (investment grade is defined as BBB- or above for S&P and BBB low or above for DBRS), APUC's ability to issue short-term debt or other securities or to market those securities would be impaired or made more difficult or expensive. Therefore, any such downgrades could have a material adverse effect on APUC's business, cost of capital, financial condition and results of operations.

The Company is not adopting or endorsing such ratings, and such ratings do not indicate APUC's assessment of its own ability to pay the interest or principal of debt securities it issues. The Company is providing such ratings only to assist with the assessment of future risks and effects of ratings on the Company's financing costs.

No assurances can be provided that any of APUC's current ratings will remain in effect for any given period of time or that a rating will not be lowered or withdrawn entirely by a rating agency if, in its judgment, circumstances in the future so warrant.

Capital Markets and Liquidity Risk

As of December 31, 2017, the Company had approximately $3,864.5 million of long-term consolidated indebtedness. Management of the Company believes, based on its current expectations as to the Company's future performance, that the cash flow from its operations and funds available to it under its revolving credit facilities and its ability to access capital markets will be adequate to enable the Company to finance its operations, execute its business strategy and maintain an adequate level of liquidity. However, expected revenue and the costs of planned capital expenditures are only estimates. Moreover, actual cash flows from operations are dependent on regulatory, market and other conditions that are beyond the control of the Company. As such, no assurance can be given that management's expectations as to future performance will be realized.

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

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

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

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

Interest Rate Risk

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

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

Based on amounts outstanding as at December 31, 2017, the impact to interest expense from changes in interest rates are as follows:

- The Corporate Credit Facility is subject to a variable interest rate and had no amounts outstanding as at December 31, 2017. As a result, a 100 basis point change in the variable rate charged would not impact interest expense;
- The Liberty Power Group's revolving credit facility is subject to a variable interest rate and had $44.8 million outstanding as at December 31, 2017. A 100 basis point change in the variable rate charged would impact interest expense by $0.4 million annually;
- The Liberty Utilities Group's revolving credit facilities are subject to a variable interest rate and had $16.3 million outstanding as at December 31, 2017. As a result, a 100 basis point change in the variable rate charged would impact interest expense by $0.2 million annually.
- The Liberty Utilities Group's commercial paper program is subject to a variable interest rate and had $7.0 million (U.S. $5.6 million) outstanding at December 31, 2017. As a result, a 100 basis point change in the variable rate charged would impact interest expense by $0.1 million annually.
- The Corporate Term Facility is subject to a variable interest rate and had $169.4 million (U.S. $135.0 million) outstanding as at December 31, 2017. A 100 basis point change in the variable rate charged would impact interest expense by $1.7 million annually;

To mitigate financing risk, from time to time APUC may seek to fix interest rates on expected future financings. In the fourth quarter of 2014, the Liberty Power Group entered into a hedge to fix the underlying interest rate for the anticipated refinancing of its $135.0 million bond maturing in July 2018. Hedge accounting treatment applies to this transaction. Consequently, changes in fair value, to the extent deemed effective, are being recorded in Other Comprehensive Income.

Foreign Currency Risk

Currency fluctuations may affect the Canadian dollar equivalent cash flows that APUC realizes from its consolidated operations because a significant portion of the Company's revenues are generated through APUC subsidiary businesses which sell electricity or provide utility services in the United States and receive proceeds from such sales in U.S. dollars. Such APUC businesses also incur costs in U.S. dollars. At the current exchange rate, approximately 93% of Adjusted EBITDA in 2017 and 93% of cash flow from operations is generated in U.S. dollars.

APUC estimates that, on an unhedged basis, a $0.10 increase in the strength of the U.S. dollar relative to the Canadian dollar would result in a net impact on U.S. operations of approximately $82.3 million ($0.22 per share) on an annual basis. In light of the currency profile of its operations, APUC pays its dividend in U.S. dollars. APUC further manages currency risk through the matching of U.S. dollar denominated long term debt for the debt requirements of its U.S. operations, thereby creating a natural hedge for the operating profit vis a vis financing costs.

APUC may enter into derivative contracts to hedge all or a portion of currency exchange rate exposure that is transactional in nature and where a natural economic hedge does not exist. To the extent that the Company does enter into currency hedges, the Company may not realize the full benefits of favorable exchange rate movement, and is subject to risks that the counterparty to the hedging contracts may prove unable or unwilling to perform their obligations under the contracts.

Effective the first quarter of 2018, APUC will begin to report its results in U.S. dollars.

Tax Risk and Uncertainty

The Company is subject to income and other taxes primarily in the United States and Canada. Changes in tax laws or interpretations thereof in the jurisdictions in which APUC does business could adversely affect the Company’s results from operations, our return to shareholders, and cash flow.

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

Development by the Liberty Power Group of renewable power generation facilities in the United States depends in part on federal tax credits and other tax incentives. Although these incentives have been extended on multiple occasions, the most recent extension provides for a multi-year step-down. While recently enacted U.S. tax reform legislation did not make any changes to the multi-year step-down, there can be no assurance that there will not be further changes in the future. If these incentives are reduced or APUC is unable to complete construction on anticipated schedules, the reduced incentives may be insufficient to support continued development and construction of renewable power facilities in the United States or may result in substantially reduced benefits from facilities that APUC is committed to complete. In addition, the Liberty Power Group has entered into certain tax equity financing transactions with financial partners for certain of its renewable power facilities in the United States, under which allocations of future cash flows to the Company from the applicable facility could be adversely affected in the event that there are changes in U.S. tax laws that apply to facilities previously placed in service.

On December 22, 2017, H.R. 1, the Tax Cuts and Jobs Act was signed into law which resulted in significant changes to U.S. tax law that will affect the Company (See *U.S. Tax Reform*).

Credit/Counterparty Risk

APUC and its subsidiaries, through its long term power purchase contracts, trade receivables, derivative financial instruments and short term investments, are subject to credit risk with respect to the ability of customers and other counterparties to perform their obligations to the Company.

Liberty Power Group's revenues are approximately 15% of total Company revenues. Approximately 94% of the Liberty Power Group's revenues are earned from large utility customers having a credit rating of Baa2 or better by Moody's, or BBB or higher by S&P, or BBB or higher by DBRS. The following chart sets out the Liberty Power Group's customers representing greater than 5% of total Liberty Power Group revenues and their credit ratings:

Counterparty	Credit Rating [1]	Approximate Annual Revenues	Percentage of Liberty Power Group Revenue
PJM Interconnection LLC	Aa2	$ 31.8	11.2%
Manitoba Hydro	Aa2	30.3	10.7%
Hydro Quebec	Aa2	29.1	10.3%
Commonwealth Edison	A3	26.4	9.3%
Xcel Energy	A3	24.2	8.6%
Pacific Gas and Electric Company	A3	24.1	8.5%
Wolverine Power Supply	A	23.5	8.3%
Ontario Electricity Financial Corporation	Aa2	22.9	8.1%
Electric Reliability Council of Texas (ERCOT)	Aa3	16.7	5.9%
Connecticut Light and Power	Baa1	16.2	5.7%
Total		**$ 245.2**	

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

The remaining revenue of the Company is primarily earned by the Liberty Utilities Group. In this regard, the credit risk attributed to the Liberty Utilities Group's accounts receivable balances at the water and wastewater distribution systems total U.S. $10.4 million which is spread over approximately 160,000 connections, resulting in an average outstanding balance of approximately U.S. $70 dollars per connection.

The natural gas distribution systems accounts receivable balances related to the natural gas utilities total U.S. $21.1 million, while electric distribution systems accounts receivable balances related to the electric utilities total U.S. $99.9 million. The natural gas and electrical utilities both derive over 84% of their revenue from residential customers.

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

Market Price Risk

The Liberty Power Group predominantly enters into long term PPAs for its generation assets and hence is not exposed to market risk for this portion of its portfolio. Where a generating asset is not covered by a power purchase contract, the Liberty Power Group may seek to mitigate market risk exposure by entering into financial or physical power hedges requiring that a specified amount of power be delivered at a specified time in return for a fixed price. There is a risk that the Company is not able to generate the specified amount of power at the specified time resulting in production shortfalls under the hedge that then requires the Company to purchase power in the merchant market. To mitigate the risk of production shortfalls under hedges, the Liberty Power Group generally seeks to structure hedges to cover less than 100% of the anticipated production, thereby reducing the risk of not producing the minimum hedge quantities. Nevertheless, due to unpredictability in the natural resource or due to grid curtailments or mechanical failures, production shortfalls may be such that the Liberty Power Group may still be forced to purchase power in the merchant market at prevailing rates to settle against a hedge.

Hedges currently put in place by the Liberty Power Group along with residual exposures to the market are detailed below:

The July 1, 2012 acquisition of the Sandy Ridge Wind Facility included a financial hedge, which commenced on January 1, 2013, for a 10 year period. The financial hedge is structured to hedge 72% of the Sandy Ridge Wind Facility's expected production volume against exposure to PJM Western Hub current spot market rates. The annual unhedged production based on long term projected averages is approximately 44,000 MW-hrs annually. Therefore, each U.S. $10 per MW-hr change in the market price would result in a change in revenue of approximately U.S. $0.4 million for the year.

A second hedge for the Sandy Ridge Wind Facility will commence on January 1, 2023, for a one year period. The financial hedge is structured to hedge 73% of the Sandy Ridge Wind Facility's expected production volume against exposure to PJM Western Hub current spot market rates. The annual unhedged production based on long term projected averages is approximately 42,000 MW-hrs annually.

The December 10, 2012 acquisition of the Senate Wind Facility included a physical hedge, which commenced on January 1, 2013, for a 15 year period. The physical hedge is structured to hedge 64% of the Senate Wind Facility's expected production volume against exposure to ERCOT North Zone current spot market rates. The annual unhedged production based on long term projected averages is approximately 188,000 MW-hrs annually. Therefore, each U.S. $10 per MW-hr change in the market price would result in a change in revenue of approximately U.S. $2.0 million for the year.

The December 10, 2012 acquisition of the Minonk Wind Facility included a financial hedge, which commenced on January 1, 2013, for a 10 year period. The financial hedge is structured to hedge 73% of the Minonk Wind Facility's expected production volume against exposure to PJM Northern Illinois Hub current spot market rates. The annual unhedged production based on long term projected averages is approximately 186,000 MW-hrs annually. Therefore, each U.S. $10 per MW-hr change in market prices would result in a change in revenue of approximately U.S. $2.0 million for the year.

A second hedge for the Minonk Wind Facility will commence on January 1, 2023, for a one year period. The financial hedge is structured to hedge 72% of the Minonk Wind Facility's expected production volume against exposure to PJM Northern Illinois Hub current spot market rates. The annual unhedged production based on long term projected averages is approximately 189,000 MW-hrs annually.

Under each of the above noted hedges, if production is not sufficient to meet the unit quantities under the hedge, the shortfall must be purchased in the open market at market rates. The effect of this risk exposure could be material but cannot be quantified as it is dependent on both the amount of shortfall and the market price of electricity at the time of the shortfall.

In addition to the above noted hedges, from time to time the Liberty Power Group enters into short-term derivative contracts (with terms of one to three months) to further mitigate market price risk exposure due to production variability. As at December 31, 2017, the Liberty Power Group had entered into hedges with a cumulative notional quantity of 7,080 MW-hrs.

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

Commodity Price Risk

The Liberty Power Group's exposure to commodity prices is primarily limited to exposure to natural gas price risk. The Liberty Utilities Group is exposed to energy and natural gas price risks at its electric and natural gas systems. In this regard, a discussion of this risk is set out as follows:

- The Sanger Thermal Facility's PPA includes provisions which reduce its exposure to natural gas price risk. In this regard, a $1.00 increase in the price of natural gas per MMBTU, based on expected production levels, would result in a decrease in net revenue by approximately $0.2 million on an annual basis.
- The Windsor Locks Thermal Facility's Energy Services Agreement includes provisions which reduce its exposure to natural gas price risk but has exposure to market rate conditions for sales above those to its primary customer. In this regard, a $1.00 increase in the price of natural gas per MMBTU, based on expected production levels, would result in a decrease in net revenue by approximately $0.1 million on an annual basis.
- The Maritime region provides short-term energy requirements to various customers at fixed rates. The energy requirements of these customers are estimated at approximately 181,000 MW-hrs in fiscal 2018, of which 170,000 MW-hrs is presently contracted. While the Tinker Hydro Facility is expected to provide the majority of the energy required to service these customers, the Maritime region anticipates having to purchase approximately 37,000 MW-hrs of its energy requirements at the ISO-NE spot rates to supplement self-generated energy should the Maritime region be able to reach the estimated 181,000 MW-hrs. The risk associated with the expected market purchases of 37,000 MW-hrs is mitigated through the use of short-term financial energy hedge contracts which cover approximately 20% of the Maritime region's anticipated purchases during the price-volatile winter months at an average rate of approximately $86 per MW-hr. For the amount of anticipated purchases not covered by hedge contracts, each U.S. $10.00 change per MW-hr in the market prices in ISO-NE would result in a change in expense of $0.3 million on an annualized basis.

The Calpeco Electric System provides electric service to the Lake Tahoe California basin and surrounding areas at rates approved by the CPUC. The Calpeco Electric System purchases the energy, capacity, and related service requirements for its customers from NV Energy via a PPA at rates reflecting NV Energy's system average costs.

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

The Granite State Electric System is an open access electric utility allowing for its customers to procure commodity services from competitive energy suppliers. For those customers that do not choose their own competitive energy supplier, Granite State Electric System provides a Default Service offering to each class of customers through a competitive bidding process. This process is undertaken semi-annually for all customers. The winning bidder is obligated to provide a full requirements service based on the actual needs of the Granite State Electric System's Default Service customers. Since this is a full requirements service, the winning bidder(s) take on the risk associated with fluctuating customer usage and commodity prices. The supplier is paid for the commodity by the Granite State Electric System which in turns receives pass-through rate recovery through a formal filing and approval process with the NHPUC on a semi-annual basis. The Granite State Electric System is only committed to the winning Default Service supplier(s) after approval by the NHPUC so that there is no risk of commodity commitment without pass-through rate recovery.

The EnergyNorth Natural Gas System purchases pipeline capacity, storage and commodity from a variety of counterparties. The EnergyNorth Natural Gas System's portfolio of assets and its planning and forecasting methodology are approved by the NHPUC bi-annually through Least Cost Integrated Resource Plan filing. In addition, EnergyNorth Natural Gas System files with the NHPUC for recovery of its transportation and commodity costs on a semi-annual basis through the Cost of Gas ("COG") filing and approval process. The EnergyNorth Natural Gas System establishes rates for its customers based on the NHPUC approval of its filed COG. These rates are designed to fully recover its anticipated transportation and commodity costs. In order to minimize commodity price fluctuations, the EnergyNorth Natural Gas System locks in a fixed price basis for approximately 14% of its normal winter period purchases under a NHPUC approved hedging program. All costs associated with the fixed basis hedging program are allowed to be a pass-through to customers through the COG filing and the approved rates in said filing. Should commodity prices increase or decrease relative to the initial semi-annual COG rate filing, the EnergyNorth Natural Gas System has the right to automatically adjust its rates going forward in order to minimize any under or over collection of its gas costs. In addition, any under collections may be carried forward with interest to the next year's corresponding COG filing, i.e. winter to winter and summer to summer.

The Midstates Gas Systems purchases pipeline capacity, storage and commodity from a variety of counterparties, and files with the three individual state commissions for recovery of its transportation and commodity costs through an annual Purchase Gas Adjustment ("PGA") filing and approval process. The Midstates Gas Systems establishes rates for its customers within the PGA filing and these rates are designed to fully recover its anticipated transportation and commodity costs. In order to minimize commodity price fluctuations, the Company has implemented a commodity hedging program designed to hedge approximately 25-50% of its non-storage related commodity purchases. All gains and losses associated with the hedging program are allowed to be a pass-through to customers through the PGA filing and are embedded in the approved rates in said filing. Rates can be adjusted on a monthly or quarterly basis in order to account for any commodity price increase or decrease relative to the initial PGA rate, minimizing any under or over collection of its gas costs.

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

Empire has a fuel cost recovery mechanism in all of its jurisdictions, as such impacts on net income exposure to commodity cost fluctuations are significantly reduced. However, cash flow could still be impacted by any increased expenditures. Empire met approximately 58% of its 2017 generation fuel supply need through coal. Approximately 97% of its 2017 coal supply was Western coal. Empire has contracts and binding proposals to supply a portion of the fuel for its coal plants through 2018. These contracts and inventory on hand satisfy approximately 56% of anticipated fuel requirements for 2018 for the Asbury Coal Facility.

Empire is exposed to changes in market prices for natural gas needed to run combustion turbine generators. Empire's natural gas procurement program is designed to manage costs to avoid volatile natural gas prices. Empire periodically enters into physical forward and financial derivative contracts with counterparties to meet future natural gas requirements by locking in prices (with respect to predetermined percentages of our expected future natural gas needs) in an attempt to lessen the volatility in fuel expenditures and improve predictability. Gains and losses associated with the hedging program are passed through to customers in the fuel adjustment clause and PGA filings and are embedded in the approved rates in such filings.

OPERATIONAL RISK MANAGEMENT

Mechanical and Operational Risks

APUC's profitability could be impacted by, among other things, equipment failure, the failure of a major customer to fulfill its contractual obligations under its PPA, reductions in average energy prices, a strike or lock-out at a facility, natural disasters, interruption in supply chain and expenses related to claims or clean-up to adhere to environmental and safety standards.

The Liberty Power Group's hydro assets utilize dams to pond water for generation and if the dams fail/breach potentially catastrophic amounts of water would flood downriver from the facility. The dams can be subjected to drought conditions and lose the ability to generate during peak load conditions, causing the facilities to fall short of either hedged or PPA committed production levels. The risks of the hydro facilities are mitigated by regular dam inspections and a maintenance program of the facility to lessen the risk of dam failure.

The Liberty Power Group's wind assets could catch on fire and, depending on the season, could ignite significant amounts of forest or crop downwind from the wind farms. The wind units could also be affected by large atmospheric conditions, which will lower wind levels below our PPA and hedge minimum production levels. The wind units can experience failures in the turbine blades or in the supporting towers. Production risks associated with the wind turbine generators failures is mitigated by properly maintaining the units, using long term maintenance agreements with the turbine O&Ms which provide for regular inspections and maintenance of property, and liability insurance policies. Icing can be mitigated by shutting down the unit as icing is detected at the site.

The Liberty Power Group's Thermal Energy Division uses natural gas and oil, and produces exhaust gases, which if not properly treated and monitored could cause hazardous chemicals to be released into the atmosphere. The units could also be restricted from purchasing gas/oil due to either shortages or pollution levels, which could hamper output of the facility. The mechanical and operational risks at the thermal facilities are mitigated through the regular maintenance of the boiler system, and by continual monitoring of exhaust gases. Fuel restrictions can be hedged in part by long term purchases.

All of the Liberty Power Group's electric generating stations are subject to mechanical breakdown. The risk of mechanical breakdown is mitigated by properly maintaining the units and by regular inspections.

The Liberty Utilities Group's water and wastewater distribution systems operate under pressurized conditions within pressure ranges approved by regulators. Should a water distribution network become compromised or damaged, the resulting release of pressure could result in serious injury or death to individuals or damage to other property.

The Liberty Utilities Group's electric distribution systems are subject to storm events, usually winter storm events, whereby power lines can be brought down, with the attendant risk to individuals and property. In addition, in forested areas, power lines brought down by wind can ignite forest fires which also bring attendant risk to individuals and property.

The Liberty Utilities Group's natural gas distribution systems are subject to risks which may lead to fire and/or explosion which may impact life and property. Risks include third party damage, compromised system integrity, type/age of pipelines, and severe weather events.

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

Regulatory Risk

Profitability of APUC businesses is, in part, dependent on regulatory climates in the jurisdictions in which those businesses operate. In the case of some Liberty Power Group hydroelectric facilities, water rights are generally owned by governments that reserve the right to control water levels, which may affect revenue.

The Liberty Utilities Group's facilities are subject to rate setting by state regulatory agencies. The Liberty Utilities Group operates in 12 different states and therefore is subject to regulation from 12 different regulatory agencies. The time between the incurrence of costs and the granting of the rates to recover those costs by state regulatory agencies is known as regulatory lag. As a result of regulatory lag, inflationary effects may impact the ability to recover expenses, and profitability could be impacted. In order to mitigate this exposure, the Liberty Utilities Group seeks to obtain approval for regulatory constructs in the states in which it operates to allow for timely recovery of operating expenses. A fundamental risk faced by any regulated utility is the disallowance of costs to be placed into its revenue requirement by the utility's regulator. To the extent proposed costs are not allowed into rates, the utility will be required to find other efficiencies or cost savings to achieve its allowed returns.

The Liberty Utilities Group regularly works with its governing authorities to manage the affairs of the business, employing both local, state level, and corporate resources.

On December 22, 2017, the Tax Cuts and Jobs Act was signed into law which resulted in significant changes to U.S. tax law. Amongst other things, the Act reduced the federal corporate income tax rates from 35% to 21%. The change in corporate tax rates will have a significant impact on the financial operations and regulatory revenue requirements of most public utilities, including the Liberty Utilities Group. The Liberty Utilities Group is working with stakeholders to understand the full implications and impact of the new law. Liberty believes that customers will be best served by dealing with Tax Reform within the context of a full regulatory rate case, where all factors that comprise rates can be considered.

Condemnation Expropriation Proceedings

The Liberty Utilities Group's distribution systems could be subject to condemnation or other methods of taking by government entities under certain conditions. Any taking by government entities would legally require fair compensation to be paid. Determination of such fair compensation is undertaken pursuant to a legal proceeding and, therefore, there is no assurance that the value received for assets taken will be in excess of book value.

Mountain Water Condemnation Proceedings

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

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

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

Apple Valley Condemnation Proceedings

On January 7, 2016, the Town of Apple Valley filed a lawsuit seeking to condemn the utility assets of Liberty Utilities (Apple Valley Ranchos Water) Corp. The Town seeks to condemn the utility assets of Apple Valley and to require a determination of fair market value. In the first phase of the case, the Court will determine the necessity of the taking by the Town. If the Court determines that necessity has been established, in a second phase, a jury will determine the fair market value of the assets being condemned. The condemnation case is currently proceeding in discovery. Resolution of the condemnation proceedings is expected to take two to three years. The Court has been briefed on a related California Environmental Quality Act ("CEQA") lawsuit (challenging the Town's compliance with CEQA in connection with the proposed condemnation) and heard oral argument in December 2017. The Court issued the CEQA decision on February 9, 2018 and denied Liberty Apple Valley's CEQA claim. As a result, the condemnation case will proceed. The Court has set a scheduling conference for the condemnation case on March 6, 2018 to potentially set a trial date on the first phase of the condemnation action.

Acquisition Risk

Part of the Company's business strategy is to acquire new generating stations and existing regulated utilities. The Company's acquisition strategy introduces exposures inherent to such transactions that may adversely affect the results of an acquisition, including delays in implementation or unexpected costs or liabilities, as well as the risk of failing to realize operating benefits or synergies. The Company mitigates these risks by following systematic procedures for integrating acquisitions, applying strict financial metrics to any potential acquisition and subjecting the process to close monitoring and review by the Board of Directors.

When acquisitions occur, significant demands can be placed on the Company's managerial, operational and financial personnel and systems. No assurance can be given that the Company's systems, procedures and controls will be adequate to support the expansion of the Company's operations resulting from the acquisition. The Company's future operating results will be affected by the ability of its officers and key employees to manage changing business conditions and to implement and improve its operational and financial controls and reporting systems.

Joint Venture Investment Risk

Certain development and operating entities that the Company has interest in are jointly owned with third parties. The Company may not have the sole discretion or ability to affect the management or operations at such facilities and thereby may not be able to make determinations on how to manage these facilities in light of changing economic circumstances. A divergence in the interests of the Company and the co-owners could negatively impact the realization of the Company's investment in the joint venture business, which may have a disproportionate economic impact relative to the Company's investment.

Asset Retirement Obligations

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

The Liberty Utilities Group's facilities are operated with the assumption that their services will be required in perpetuity and there are no contractual decommissioning requirements. In order to remain in compliance with the applicable regulatory bodies, the Liberty Utilities Group has regular programs at each facility to ensure its equipment is properly maintained and replaced on a cyclical basis. These costs can generally be included in the facility's rate base and thus the Liberty Utilities Group expects to be allowed to earn a return on such investment.

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

Cycles and Seasonality

Liberty Power Group

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

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

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

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

Liberty Utilities Group

The Liberty Utilities Group’s demand for water is affected by weather conditions and temperature. Demand for water during warmer months is generally greater than cooler months due to requirements for irrigation, swimming pools, cooling systems and other outside water use. If there is above normal rainfall or rainfall is more frequent than normal the demand for water may decrease, adversely affecting revenues.

The Liberty Utilities Group’s demand for energy from its electric distribution systems is primarily affected by weather conditions and conservation initiatives. The Liberty Utilities Group provides information and programs to its customers to encourage the conservation of energy. In turn, demand may be reduced which could have short term adverse impacts on revenues.

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

The Company attempts to mitigate the above noted risks by seeking regulatory mechanisms during rate case proceedings. While not all regulatory jurisdictions have approved mechanisms to mitigate demand fluctuations, to date, the Liberty Utilities Group has successfully obtained regulatory approval to implement such decoupling mechanisms in 4 of 12 states representing approximately 25% of customers. An example of such a mechanism is seen at the Peach State Gas System in Georgia, where a weather normalization adjustment is applied to customer bills during the months of October through May that adjusts commodity rates to stabilize the revenues of the utility for changes in billing units attributable to weather patterns. The Liberty Utilities Group is presently seeking weather related decoupling mechanism for its utilities in Missouri and New Hampshire.

Development and Construction Risk

The Company actively engages in the development and construction of new power generation facilities. There is always a risk that material delays and/or cost overruns could be incurred in any of the projects planned or currently in construction affecting the company’s overall performance. There are risks that actual costs may exceed budget estimates, delays may occur in obtaining permits and materials, suppliers and contractors may not perform as required under their contracts, there may be inadequate availability, productivity or increased cost of qualified craft labor, start-up activities may take longer than planned, the scope and timing of projects may change, and other events beyond the Company's control may occur that may materially affect the schedule, budget, cost and performance of projects. Regulatory approvals can be challenged by a number of mechanisms which vary across state and provincial jurisdictions. Such permitting challenges could identify issues that may result in permits being modified or revoked.

Risks Specific to Renewable Generation Projects:

The strength and consistency of the wind resource will vary from the estimate set out in the initial wind studies that were relied upon to determine the feasibility of the wind facility. If weather patterns change or the historical data proves not to accurately reflect the strength and consistency of the actual wind, the assumptions underlying the financial projections as to the amount of electricity to be generated by the facility may be different and cash could be impacted.

The amount of solar radiance will vary from the estimate set out in the initial solar studies that were relied upon to determine the feasibility of the solar facility. If weather patterns change or the historical data proves not to accurately reflect the strength and consistency of the solar radiance, the assumptions underlying the financial projections as to the amount of electricity to be generated by the facility may be different and cash could be impacted.

For certain of its development projects, the Company relies on financing from third party tax equity Investors. These investors typically provide funding upon commercial operation of the facility. Should certain facilities not meet the conditions required for tax equity funding, expected returns from the facilities may be impacted.

Litigation Risks and Other Contingencies

APUC and certain of its subsidiaries are involved in various litigations, claims and other legal and regulatory proceedings that arise from time to time in the ordinary course of business. Any accruals for contingencies related to these items are recorded in the financial statements at the time it is concluded that a material financial loss is likely and the related liability is estimable. Anticipated recoveries under existing insurance policies are recorded when reasonably assured of recovery.

See further discussion of claims made by or against APUC or its subsidiaries in *Regulatory Risk*.

Cybersecurity Risk

The Company's information technology systems may be vulnerable to potential risks from cybersecurity attacks. Attacks can be caused by malware, viruses, email attachments, acts of war or terrorism and can originate from individuals from both inside and outside the organization. An attack could result in service disruptions, system failures, the disclosure of personal customer and employee information, and could lead to an adverse effect on the Company's financial performance. A breach of personal or confidential information may also occur as a result of non-cyber means, such as breach of physical security. Should a material breach occur the Company may not be able to recover all costs and losses through insurance, legal or regulatory processes.

The Company mitigates these risks by maintaining a cybersecurity program that is overseen by the Board of Directors, and executed by a cross functional management team. The program is intended to provide adequate controls for the appropriate protection of critical business systems. These controls have been put into place to mitigate potential risks, and to improve the organization's capability to respond and recover from any potential cyber incident.

Energy Consumption and Advancement in Technologies Risk

The Liberty Utilities Group's operations are subject to changes in demand for energy which are impacted by general economic conditions, customer's focus on energy efficiency, and advancements in new technologies.

The Liberty Utilities Group is actively involved in working with governments and customers to ensure these changes in consumption do not negatively impact the services provided. Furthermore, through its strategic initiatives the Liberty Utilities Group is constantly looking for ways to maintain the Company's competitive advantage.

Uninsured Risk

The Company maintains insurance for accidental loss and potential liabilities to third parties. However, there are certain elements of the Liberty Utilities Group's regulated utilities that are not fully insured as the cost of the coverage is not economically viable. In the event that a liability event or loss is not covered through insurance the Liberty Utilities Group would apply to their respective regulator to request recovery through increased customer rates. Cost recovery through this mechanism is subject to regulatory approval and is therefore uncertain.

Insurance coverage for the rest of the Company is also subject to policy conditions and exclusions, coverage limits, and various deductibles, and not all types of liabilities and losses may be covered by insurance, in which case the Company may be financially exposed.

QUARTERLY FINANCIAL INFORMATION

The following is a summary of unaudited quarterly financial information for the eight quarters ended December 31, 2017:

(all dollar amounts in $ millions except per share information)	1st Quarter 2017	2nd Quarter 2017	3rd Quarter 2017	4th Quarter 2017
Revenue	$ 557.9	$ 453.2	$ 443.3	$ 523.4
Net earnings attributable to shareholders	26.0	47.7	59.4	60.0
Net earnings per share	0.07	0.12	0.15	0.14
Adjusted Net Earnings	88.1	53.3	64.9	85.9
Adjusted Net Earnings per share	0.25	0.13	0.16	0.20
Adjusted EBITDA	254.8	197.6	197.5	233.4
Total assets	10,880.7	10,528.6	10,306.7	10,533.6
Long term debt[1]	4,773.6	4,418.0	4,435.1	3,864.5
Dividend declared per common share	$ 0.15	$ 0.16	$ 0.15	$ 0.15

	1st Quarter 2016	2nd Quarter 2016	3rd Quarter 2016	4th Quarter 2016
Revenue	$ 341.7	$ 222.8	$ 221.3	$ 310.2
Net earnings attributable to shareholders	42.0	24.8	17.7	46.3
Net earnings per share	0.15	0.08	0.06	0.16
Adjusted Net Earnings	56.1	30.9	26.6	51.4
Adjusted Net Earnings per share	0.21	0.11	0.09	0.18
Adjusted EBITDA	147.9	99.2	91.4	138.3
Total assets	5,615.5	5,555.0	6,020.8	8,249.5
Long term debt[1]	2,214.5	2,199.9	2,380.8	4,272.0
Dividend declared per common share	$ 0.13	$ 0.14	$ 0.14	$ 0.14

[1] Includes current portion of long-term debt, long-term debt and convertible debentures.

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

Quarterly revenues have fluctuated between $221.3 million and $557.9 million over the prior two year period. A number of factors impact quarterly results including acquisitions, seasonal fluctuations, and winter and summer rates built into the PPAs. In addition, a factor impacting revenues year over year is the fluctuation in the strength of the Canadian dollar relative to the U.S. dollar which can result in significant changes in reported revenue from U.S. operations.

Quarterly net earnings attributable to shareholders have fluctuated between $17.7 million and $60 million over the prior two year period. Earnings have been significantly impacted by non-cash factors such as deferred tax recovery and expense, impairment of intangibles, property, plant and equipment and mark-to-market gains and losses on financial instruments.

DISCLOSURE CONTROLS AND PROCEDURES

APUC's management carried out an evaluation as of December 31, 2017, under the supervision of and with the participation of APUC's Chief Executive Officer ("CEO") and Chief Financial Officer ("CFO"), of the effectiveness of the design and operations of APUC's disclosure controls and procedures (as defined in Rule 13a-15(e) and Rule 15d-15 (e) under the Securities Exchange Act of 1934, as amended (the "Exchange Act")). Based on that evaluation, the CEO and the CFO have concluded that as of December 31, 2017, APUC's disclosure controls and procedures are effective to provide reasonable assurance that information required to be disclosed by APUC in reports that it files or submits under the Exchange Act is recorded, processed, summarized, and reported within the time periods specified in SEC rules and forms, and is accumulated and communicated to management, including the CEO and CFO, as appropriate, to allow timely decisions regarding required disclosure.

MANAGEMENT REPORT ON INTERNAL CONTROLS OVER FINANCIAL REPORTING

Management, including the CEO and CFO, is responsible for establishing and maintaining adequate internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with U.S. GAAP.

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

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

During the year ended December 31, 2017, the Company acquired Empire. Management is in the process of evaluating the existing controls and procedures of Empire and integrating financial reporting and controls for Empire into the Company's internal control over financial reporting. The financial information for this acquisition is included in this MD&A and in *note 3* to the consolidated financial statements. As permitted by National Instrument 52-109 and the SEC, due to the complexity associated with assessing internal controls during integration efforts, the Company excluded this acquisition from its assessment of the effectiveness of the Company's internal controls over financial reporting (representing approximately 30% of our total assets as of December 31, 2017 and approximately 41% of our revenues and 35% of our net income for the year ended December 31, 2017).

Management assessed the effectiveness of the Company's internal control over financial reporting as of December 31, 2017, based on the framework established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). This assessment included review of the documentation of controls, evaluation of the design effectiveness of controls, testing of the operating effectiveness of controls, and a conclusion on this evaluation. Based on this assessment, management concluded that the Company's internal control over financial reporting was effective as of December 31, 2017 to provide reasonable assurance regarding the reliability of financial reporting and the preparation of consolidated financial statements for external reporting purposes in accordance with U.S. GAAP. Management reviewed the results of its assessment with the Audit Committee of the Board of Directors of APUC.

CHANGES IN INTERNAL CONTROLS OVER FINANCIAL REPORTING

For the twelve months ended December 31, 2017, there has been no change in the Company's internal control over financial reporting that has materially affected, or is reasonably likely to materially affect, the Company's internal control over financial reporting. The Company continues to implement its internal control structure over the operations of the acquired business discussed above.

INHERENT LIMITATIONS ON EFFECTIVENESS OF CONTROLS

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

CRITICAL ACCOUNTING ESTIMATES AND POLICIES

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

APUC's significant accounting policies and new accounting standards are discussed in *notes 1* and *2* to the consolidated financial statements, respectively. Management believes the following accounting policies involve the application of critical accounting estimates. Accordingly, these accounting estimates have been reviewed and discussed with the Audit Committee of the Board of Directors of APUC.

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

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

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

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

A recoverability analysis was performed in 2017 for wind generating assets operating without a PPA and in 2016 for wind and small hydro generating assets without a PPA. No impairment provision was required in 2017 or 2016. A quantitative assessment of goodwill performed as at September 30, 2014 concluded that the fair value of each reporting unit substantially exceeded their carrying value. In 2017 and 2016, Management assessed qualitative and quantitative factors for each of the reporting units that were allocated goodwill. No goodwill impairment provision was required.

Measurement of Deferred Taxes

On December 22, 2017, the U.S. government enacted the Tax Cuts and Jobs Act (the "Act"). The Act made broad and complex changes to the U.S. tax code which impacted 2017 including, but not limited to, reducing the U.S. federal corporate tax rate from 35% to 21% and introducing 100% expensing for certain capital expenditures, excluding regulated utilities, made after September 27, 2017. Management's judgment is required to measure the deferred taxes assets and liabilities at the enactment date based on these changes. Where requirements of the implementation of the new Act are incomplete, management uses judgments and assumptions to calculate a reasonable provisional amount to include in the Company's financial statements.

Valuation of Deferred Tax Assets

In assessing the realization of deferred tax assets, management considers whether it is more likely than not that some portion or all of the deferred tax assets will not be realized and provides any necessary valuation allowances as required. Management evaluates the probability of realizing deferred tax assets by reviewing a forecast of future taxable income together with Management's intent and ability to implement tax planning strategies, if necessary, to realize deferred tax assets. Although at this time Management considers it more likely than not that it will have sufficient taxable income to realize the deferred tax assets, there can be no assurance that the company will generate sufficient taxable income in the future to utilize these deferred tax assets. Management also assesses the ability to utilize tax attributes, including those in the form of carryforwards, for which the benefits have already been reflected in the financial statements. Management's assessment has been impacted by the tax reform discussed above.

Accounting for Rate Regulation

Accounting guidance for regulated operations provides that rate-regulated entities account for and report assets and liabilities consistent with the recovery of those incurred costs in rates if the rates established are designed to recover the costs of providing the regulated service and if the competitive environment makes it probable that such rates can be charged and collected. This accounting guidance is applied to the Liberty Utilities Group's operations.

Certain expenses and revenues subject to utility regulation or rate determination normally reflected in income are deferred on the balance sheet as regulatory assets or liabilities and are recognized in income as the related amounts are included in service rates and recovered from or refunded to customers. Regulatory assets and liabilities are recorded when it is probable that these items will be recovered or reflected in future rates. Determining probability requires significant judgment on the part of management and includes, but is not limited to, consideration of testimony presented in regulatory hearings, proposed regulatory decisions, final regulatory orders and industry practice. If events were to occur that would make the recovery of these assets and liabilities no longer probable, these regulatory assets and liabilities would be required to be written off or written down.

Unbilled Energy Revenues

Revenues related to natural gas, electricity and water delivery are generally recognized upon delivery to customers. The determination of customer billings is based on a systematic reading of meters throughout the month. At the end of each month, amounts of natural gas, energy or water provided to customers since the date of the last meter reading are estimated, and the corresponding unbilled revenue is recorded. Factors that can impact the estimate of unbilled energy include, but are not limited to, seasonal weather patterns compared to normal, total volumes supplied to the system, line losses, economic impacts, and composition of customer classes. Estimates are reversed in the following month and actual revenue is recorded based on subsequent meter readings.

The Financial Accounting Standards Board ("FASB") issued a revenue recognition standard codified as ASC 606, Revenue from Contracts with Customers. The Company expects the adoption of Topic 606 will have an immaterial impact on the consolidated financial statements and the pattern of revenue recognition. The Company intends to adopt the new revenue recognition standard using the modified retrospective method effective January 1, 2018.

Derivatives

APUC uses derivative instruments to manage exposure to changes in commodity prices, foreign exchange rates, and interest rates. Management’s judgment is required to determine if a transaction meets the definition of a derivative and, if it does, whether the normal purchases and sales exception applies or whether individual transactions qualify for hedge accounting treatment. Management’s judgment is also required to determine the fair value of derivative transactions. APUC determines the fair value of derivative instruments based on forward market prices in active markets obtained from external parties adjusted for nonperformance risk. A significant change in estimate could affect APUC’s results of operations if the hedging relationship was considered no longer effective.

Pension and Post-employment Benefits

The obligations and related costs of defined benefit pension and post-employment benefit plans are calculated using actuarial concepts, which include critical assumptions related to the discount rate, mortality rate, compensation increase, expected rate of return on plan assets and medical cost trend rates. These assumptions are important elements of expense and/or liability measurement and are updated on an annual basis, or upon the occurrence of significant events. The Company used the new mortality improvement scale (MP-2017) recently released by the Society of Actuaries adjusted to reflect the 2017 Social Security Administration ultimate improvement rates.

The FASB issued ASU 2017-07 Compensation—Retirement Benefits (Topic 715): Improving the Presentation of Net Periodic Pension Cost and Net Periodic Post-retirement Benefit Cost, for reporting of defined benefit pension cost and post-retirement benefit cost ("net benefit cost") in the financial statements. The Company will adopt this guidance effective January 1, 2018. Following the effective date of this Accounting Standards Update ("ASU"), the Company expects its regulated operations to only capitalize the service costs component and therefore no regulatory to U.S. GAAP reporting differences are anticipated. The Company intends to apply the practical expedient for retrospective application on the statement of operations.

Sensitivities

The sensitivities of key assumptions used in measuring accrued benefit obligations and benefit plan cost for 2017 are outlined in the following table. They are calculated independently of each other. Actual experience may result in changes in a number of assumptions simultaneously. The types of assumptions and method used to prepare the sensitivity analysis has not changed from previous periods and is consistent with the calculation of the retirement benefit obligations and net benefit plan cost recognized in the consolidated financial statements.

	2017 Pension Plans		2017 OPEB Plans	
(all dollar amounts in $ millions)	Accrued Benefit Obligation	Net Periodic Pension Cost	Accumulated Postretirement Benefit Obligation	Net Periodic Postretirement Benefit Cost
Discount Rate				
1% increase	(65.6)	(4.4)	(31.5)	(1.9)
1% decrease	81.1	6.7	39.7	2.1
Future compensation rate				
1% increase	0.2	1.5	—	—
1% decrease	(0.2)	(1.3)	—	—
Expected return on plan assets				
1% increase	—	(4.5)	—	(1.4)
1% decrease	—	4.5	—	1.4
Life expectancy				
10% increase	38.0	3.3	19.7	1.6
10% decrease	(39.9)	(2.8)	(18.8)	(1.8)
Health care trend				
1% increase	—	—	38.0	4.3
1% decrease	—	—	(30.1)	(3.3)

Business Combinations

The Company has completed a number of business acquisitions in the past few years. Management's judgment is required to estimate the purchase price, to identify and to fair value all assets and liabilities acquired. The determination of the fair value of assets and liabilities acquired is based upon management’s estimates and certain assumptions generally included in a present value calculation of the related cash flows.

Acquired assets and liabilities assumed that are subject to critical estimates include regulated property, plant and equipment, regulatory assets and liabilities, long-term debt and pension and OPEB obligations. The fair value of regulated property, plant and equipment is assessed using an income approach where the estimated cash flows of the assets are calculated using the approved tariff and discounted at the approved rate of return. The fair value of regulatory assets and liabilities considers the estimated timing of the recovery or refund to customers through the rate making process. The fair value of long-term debt is determined using a discounted cash flow method and current interest rates. The pension and OPEB obligations are valued by external actuaries using the guidelines of ASC 805, Business combinations.

Additional disclosure of APUC’s critical accounting estimates is also available on SEDAR at www.sedar.com and on the APUC website at www.AlgonquinPowerandUtilities.com.

MANAGEMENT'S REPORT

Financial Reporting

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

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

Internal Control over Financial Reporting

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

Management assessed the effectiveness of the Company's internal control over financial reporting as of December 31, 2017, based on the framework established in *Internal Control – Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on this assessment, management concluded that the Company maintained effective internal control over financial reporting as of December 31, 2017.

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

March 7, 2018

/s/ Ian Robertson	/s/ David Bronicheski
Chief Executive Officer	Chief Financial Officer

REPORT OF REGISTERED PUBLIC ACCOUNTING FIRM

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

Opinion on the Consolidated Financial Statements

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

In our opinion, the consolidated financial statements present fairly, in all material respects, the consolidated financial position of the Company as at December 31, 2017 and December 31, 2016, and its consolidated financial performance and its consolidated cash flows for the years then ended in accordance with United States generally accepted accounting principles.

Report on internal control over financial reporting

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (“PCAOB”), the Company’s internal control over financial reporting as of December 31, 2017, based on the criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (“COSO”), and our report dated March 7, 2018 expressed an unqualified opinion on the effectiveness of the Company’s internal control over financial reporting.

Basis for Opinion

Management’s Responsibility for the Consolidated Financial Statements

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

Auditors’ Responsibility

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

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

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

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

/s/ Ernst & Young LLP

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

Toronto, Canada

March 7, 2018

REPORT OF REGISTERED PUBLIC ACCOUNTING FIRM

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

Opinion on Internal Control over Financial Reporting

We have audited Algonquin Power & Utilities Corp.'s internal control over financial reporting as of December 31, 2017, based on criteria established in Internal Control-Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (the "COSO criteria"). In our opinion, Algonquin Power & Utilities Corp. (the Company) maintained, in all material respects, effective internal control over financial reporting as of December 31, 2017, based on the COSO criteria.

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

Basis for Opinion

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

We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

Definition and Limitations of Internal Control Over Financial Reporting

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

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

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

/s/ Ernst & Young LLP

Toronto, Canada

March 7, 2018

Algonquin Power & Utilities Corp.
Consolidated Balance Sheets

(thousands of Canadian dollars)

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

Algonquin Power & Utilities Corp.
Consolidated Balance Sheets

(thousands of Canadian dollars)

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

See accompanying notes to consolidated financial statements

Algonquin Power & Utilities Corp.
Consolidated Statements of Operations

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

See accompanying notes to consolidated financial statements

Algonquin Power & Utilities Corp.
Consolidated Statements of Comprehensive Income

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

See accompanying notes to consolidated financial statements

Algonquin Power & Utilities Corp.
Consolidated Statement of Equity

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

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

Algonquin Power & Utilities Corp.
Consolidated Statement of Equity

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

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

See accompanying notes to consolidated financial statements

Algonquin Power & Utilities Corp.
Consolidated Statements of Cash Flows

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

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

See accompanying notes to consolidated financial statements

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

1. Significant accounting policies

(a) Basis of preparation

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

(b) Basis of consolidation

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

(c) Business combinations, intangible assets and goodwill

The Company accounts for acquisitions of entities or assets which meet the definition of a business as business combinations. The determination of whether the definition of a business has been met for a development stage project depends on the stage of development (permitting, customer contracting, financing, construction) and the significance of the development risk with respect to achieving commercial operation. Business combinations are accounted for using the acquisition method. Assets acquired and liabilities assumed are measured at their fair value at the acquisition date. Acquisition costs are expensed in the period incurred. When the set of activities does not represent a business, the transaction is accounted for as an asset acquisition and includes acquisitions costs.

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

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

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

(d) Accounting for rate regulated operations

The regulated utility operating companies owned by the Company are subject to rate regulation generally overseen by the public utility commission of the states in which they operate (the "Regulator"). The Regulator provides the final determination of the rates charged to customers. APUC's regulated utility operating companies are accounted for under the principles of U.S. Financial Accounting Standards Board ("FASB") ASC Topic 980, Regulated Operations ("ASC 980"). Under ASC 980, regulatory assets and liabilities are recorded to the extent that they represent probable future revenue or expenses associated with certain charges or credits that will be recovered from or refunded to customers through the rate making process. Included in note 7 "Regulatory matters" are details of regulatory assets and liabilities, and their current regulatory treatment.

1. Significant accounting policies (continued)

(d) Accounting for rate regulated operations (continued)

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

The electric, gas and water utilities' accounts are maintained in accordance with the Uniform System of Accounts prescribed by the Federal Energy Regulatory Commission ("FERC"), the Regulator and National Association of Regulatory Utility Commissioners.

(e) Cash and cash equivalents

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

(f) Restricted cash

Restricted cash represents reserves and amounts set aside pursuant to requirements of various debt agreements and requirements of ISO New England, Inc. As of December 31, 2016, restricted cash also included cash of U.S. $1,495,774 transfered to a paying agent for purposes of distribution to holders of common shares of The Empire District Electric Company and its subsidiaries ("Empire") on January 1, 2017 (note 3(a)). Cash reserves segregated from APUC's cash balances are maintained in accounts administered by a separate agent and disclosed separately as restricted cash in these consolidated financial statements. APUC cannot access restricted cash without the prior authorization of parties not related to APUC.

(g) Accounts receivable

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

(h) Fuel and natural gas in storage

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

(i) Supplies and consumables inventory

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

(in thousands of Canadian 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.

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

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

Investment tax credits and government grants related to capital expenditures are recorded as a reduction to the cost of assets and are amortized at the rate of the related asset as a reduction to depreciation expense. Contributions in aid of construction represent amounts contributed by customers, governments and developers to assist with the funding of some or all of the cost of utility capital assets. It also includes amounts initially recorded as advances in aid of construction (note 13(a)) but where the advance repayment period has expired. These contributions are recorded as a reduction in the cost of utility assets and are amortized at the rate of the related asset as a reduction to depreciation expense. Investment tax credits and government grants related to operating expenses such as maintenance and repairs costs are recorded as a reduction of the related expense.

(in thousands of Canadian 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	
	2017	**2016**	**2017**	**2016**
Generation	**3 - 60**	3 - 60	**33**	32
Distribution	**5 - 100**	5 - 100	**40**	41
Equipment	**5 - 50**	5 - 50	**13**	11

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

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

(k) Commonly owned facilities

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

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

(l) Impairment of long-lived assets

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

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

(m) Variable interest entities

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

1. Significant accounting policies (continued)

(m) Variable interest entities (continued)

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

Total net book value of generating assets and long-term debt of these facilities amounts to $84,550 (2016 - $87,189) and $35,914 (2016 - $40,398), respectively. The portion of long-term debt which has recourse to the Company is $3,900 (2016 - $6,900). The financial performance of these facilities reflected on the consolidated statements of operations includes non-regulated energy sales of $22,743 (2016 - $29,132), operating expenses and amortization of $5,564 (2016 - $6,175) and interest expense of $3,573 (2016 - $4,064).

(n) Long-term investments and notes receivable

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

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

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

(o) Pension and other post-employment plans

The Company has established defined contribution pension plans, defined benefit pension plans, other post-employment benefit ("OPEB"), supplemental retirement program ("SERP") plans for its various employee groups in Canada and the United States. Employer contributions to the defined contribution pension plans are expensed as employees render service. The Company recognizes the funded status of its defined benefit pension plans, OPEB and SERP plans on the consolidated balance sheets. The Company's expense and liabilities are determined by actuarial valuations, using assumptions that are evaluated annually as of December 31, including discount rates, mortality, assumed rates of return, compensation increases, turnover rates and healthcare cost trend rates. The impact of modifications to those assumptions and modifications to prior services are recorded as actuarial gains and losses in accumulated other comprehensive income ("AOCI") and amortized to net periodic cost over future periods using the corridor method. The costs of the Company's pension for employees are expensed over the periods during which employees render service and are recognized as part of administrative expenses in the consolidated statements of operations.

1. Significant accounting policies (continued)

(p) Asset retirement obligations

The Company recognizes a liability for asset retirement obligations based on the fair value of the liability when incurred, which is generally upon acquisition, during construction or through the normal operation of the asset. Concurrently, the Company also capitalizes an asset retirement cost, equal to the estimated fair value of the asset retirement obligation, by increasing the carrying value of the related long-lived asset. The asset retirement costs are depreciated over the asset's estimated useful life and are included in depreciation and amortization expense on the consolidated statements of operations, or regulatory assets when the amount is recoverable through rates. Increases in the asset retirement obligation resulting from the passage of time are recorded as accretion of asset retirement obligation in the consolidated statements of operations, or regulatory assets when the amount is recoverable through rates. Actual expenditures incurred are charged against the obligation.

(q) Share-based compensation

The Company has several share-based compensation plans: a share option plan; an employee share purchase plan ("ESPP"); a deferred share unit ("DSU") plan; and a performance share unit ("PSU") plan. Equity classified awards are measured at the grant date fair value of the award. The Company estimates grant date fair value of options using the Black-Scholes option pricing model. The fair value is recognized over the vesting period of the award granted, adjusted for estimated forfeitures. The compensation cost is recorded as administrative expense in the consolidated statements of operations and additional paid-in capital in equity. Additional paid-in capital is reduced as the awards are exercised, and the amount initially recorded in additional paid-in capital is credited to common shares.

(r) Non-controlling interests

Non-controlling interests represent the portion of equity ownership in subsidiaries that is not attributable to the equity holders of APUC. Non-controlling interests are initially recorded at fair value and subsequently adjusted for the proportionate share of earnings and other comprehensive income ("OCI") attributable to the non-controlling interests and any dividends or distributions paid to the non-controlling interests.

If a transaction results in the acquisition of all, or part, of a non-controlling interest in a consolidated subsidiary, the acquisition of the non-controlling interest is accounted for as an equity transaction. No gain or loss is recognized in net earnings or comprehensive income as a result of changes in the non-controlling interest, unless a change results in the loss of control by the Company.

Certain of the Company's U.S. based wind and solar businesses are organized as limited liability corporations ("LLC") and partnerships and have non-controlling Class A membership equity investors ("Class A partnership units" or "Class A Equity Investors") which are entitled to allocations of earnings, tax attributes and cash flows in accordance with contractual agreements. These LLC and partnership's agreements have liquidation rights and priorities that are different from the underlying percentages ownership interests. In those situations, simply applying the percentage ownership interest to GAAP net income in order to determine earnings or losses would not accurately represent the income allocation and cash flow distributions that will ultimately be received by the investors. As such, the share of earnings attributable to the non-controlling interest holders in these entities is calculated using the Hypothetical Liquidation at Book Value ("HLBV") method of accounting (note 19).

The HLBV method uses a balance sheet approach. A calculation is prepared at each balance sheet date to determine the amount that Class A Equity Investors would receive if an equity investment entity were to liquidate all of its assets and distribute that cash to the investors based on the contractually defined liquidation priorities. The difference between the calculated liquidation distribution amounts at the beginning and the end of the reporting period is the Class A Equity Investors' share of the earnings or losses from the investment for that period. Due to certain mandatory liquidation provisions of the LLC and partnership agreements, this could result in a net loss to APUC's consolidated results in periods in which the Class A Equity Investors report net income. The calculation varies in its complexity depending on the capital structure and the tax considerations of the investments.

1. Significant accounting policies (continued)

(r) Non-controlling interests (continued)

Equity instruments subject to redemption upon the occurrence of uncertain events not solely within APUC's control are classified as temporary equity on the consolidated balance sheets. The Company records temporary equity at issuance based on cash received less any transaction costs. As needed, the Company reevaluates the classification of its redeemable instruments, as well as the probability of redemption. If the redemption amount is probable or currently redeemable, the Company records the instruments at their redemption value. Increases or decreases in the carrying amount of a redeemable instrument are recorded within deficit. When the redemption feature lapses or other events cause the classification of an equity instrument as temporary equity to be no longer required, the existing carrying amount of the equity instrument is reclassified to permanent equity at the date of the event that caused the reclassification.

(s) Recognition of revenue

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

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

Revenue related to utility electricity and natural gas sales and distribution are recorded when the electricity or natural gas is delivered. At the end of each month, the electricity and natural gas delivered to the customers from the date of their last meter read to the end of the month is estimated and the corresponding unbilled revenue is recorded. These estimates of unbilled revenue and sales are based on the ratio of billable days versus unbilled days, amount of electricity or natural gas procured during that month, historical customer class usage patterns, weather, line loss, unaccounted-for gas and current tariffs.

Revenue for certain of the Company's regulated utilities is subject to revenue decoupling mechanisms approved by their respective regulators which require to charge approved annual delivery revenue on a systematic basis over the fiscal year. As a result, the difference between delivery revenue calculated based on metered consumption and approved delivery revenue is recorded as a regulatory asset or liability to reflect future recovery or refund, respectively, from customers (note 7(e)).

Water reclamation and distribution revenues are recorded when water is processed or delivered to customers. At the end of each month, the water delivered and wastewater collected from the customers from the date of their last meter read to the end of the month is estimated and the corresponding unbilled revenue is recorded. These estimates of unbilled revenue are based on the ratio of billable days versus unbilled days, amount of water procured and collected during that month, historical customer class usage patterns and current tariffs.

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

Revenue is recorded net of sales taxes.

1. Significant accounting policies (continued)

(t) Foreign currency translation

APUC's reporting currency is the Canadian dollar.

The Company's U.S. operations are determined to have the U.S. dollar as their functional currency since the preponderance of operating, financing and investing transactions are denominated in U.S. dollars. The financial statements of these operations are translated into Canadian dollars using the current rate method, whereby assets and liabilities are translated at the rate prevailing at the balance sheet date, and revenue and expenses are translated using average rates for the period.

Unrealized gains or losses arising as a result of the translation of the financial statements of these entities are reported as a component of OCI and are accumulated in a component of equity on the consolidated balance sheets, and are not recorded in income unless there is a complete or substantially complete sale or liquidation of the investment.

(u) Income taxes

Income taxes are accounted for using the asset and liability method. Deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of assets and liabilities and their respective tax bases. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. A valuation allowance is recorded against deferred tax assets to the extent that it is considered more likely than not that the deferred tax asset will not be realized. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in earnings in the period that includes the date of enactment (note 20). Investment tax credits for our rate regulated operations are deferred and amortized as a reduction to income tax expense over the estimated useful lives of the properties. Other income tax credits are treated as a reduction to income tax expense in the year the credit arises or future periods to the extent that realization of such benefit is more likely than not.

The organizational structure of APUC and its subsidiaries is complex and the related tax interpretations, regulations and legislation in the tax jurisdictions in which they operate are continually changing. As a result, there can be tax matters that have uncertain tax positions. The Company recognizes the effect of income tax positions only if those positions are more likely than not of being sustained. Recognized income tax positions are measured at the largest amount that is greater than 50% likely of being realized. Changes in recognition or measurement are reflected in the period in which the change in judgment occurs.

(v) Financial instruments and derivatives

Accounts receivable and notes receivable are measured at amortized cost. Long-term debt and Series C preferred shares are measured at amortized cost using the effective interest method, adjusted for the amortization or accretion of premiums or discounts.

Transaction costs that are directly attributable to the acquisition of financial assets are accounted for as part of the asset's carrying value at inception. Transaction costs related to a recognized debt liability are presented in the consolidated balance sheets as a direct deduction from the carrying amount of that debt liability, consistent with debt discounts and premiums. Costs of arranging the Company's revolving credit facilities and intercompany loans are recorded in other assets. Deferred financing costs, premiums and discounts on long-term debt are amortized using the effective interest method while deferred financing costs relating to the revolving credit facilities and intercompany loans are amortized on a straight-line basis over the term of the respective instrument.

The Company uses derivative financial instruments as one method to manage exposures to fluctuations in exchange rates, interest rates and commodity prices. APUC recognizes all derivative instruments as either assets or liabilities on the consolidated balance sheets at their respective fair values. The fair value recognized on derivative instruments executed with the same counterparty under a master netting arrangement are presented on a gross basis on the consolidated balance sheets. The amounts that could net settle are not significant. The Company applies hedge accounting to some of its financial instruments used to manage its foreign currency risk exposure, interest risk and price risk exposure associated with sales of generated electricity.

1. Significant accounting policies (continued)

(v) Financial instruments and derivatives (continued)

For derivatives designated in a cash flow hedge relationship, the effective portion of the change in fair value is recognized in OCI. The ineffective portion is immediately recognized in earnings. The amount recognized in AOCI is reclassified to earnings in the same period as the hedged cash flows affect earnings under the same line item in the consolidated statements of operations as the hedged item. If the hedging instrument no longer meets the criteria for hedge accounting, expires or is sold, terminated, exercised, or the designation is revoked, then hedge accounting is discontinued prospectively. The amount remaining in AOCI is transferred to the consolidated statements of operations in the same period that the hedged item affects earnings. If the forecasted transaction is no longer expected to occur, then the balance in AOCI is recognized immediately in earnings.

Foreign currency gain or loss on derivative or financial instruments designated as a hedge of the foreign currency exposure of a net investment in foreign operations that are effective as a hedge are reported in the same manner as the translation adjustment (in OCI) related to the net investment. To the extent that the hedge is ineffective, such differences are recognized in earnings.

The Company's electric distribution and thermal generation facilities enter into power and gas purchase contracts for load serving and generation requirements. These contracts meet the exemption for normal purchase and normal sales and as such, are not required to be recorded at fair value as derivatives and are accounted for on an accrual basis. Counterparties are evaluated on an ongoing basis for non-performance risk to ensure it does not impact the conclusion with respect to this exemption.

(w) Fair value measurements

The Company utilizes valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs to the extent possible. The Company determines fair value based on assumptions that market participants would use in pricing an asset or liability in the principal or most advantageous market. When considering market participant assumptions in fair value measurements, the following fair value hierarchy distinguishes between observable and unobservable inputs, which are categorized in one of the following levels:

- Level 1 Inputs: Unadjusted quoted prices in active markets for identical assets or liabilities accessible to the reporting entity at the measurement date.
- Level 2 Inputs: Other than quoted prices included in Level 1, inputs that are observable for the asset or liability, either directly or indirectly, for substantially the full term of the asset or liability.
- Level 3 Inputs: Unobservable inputs for the asset or liability used to measure fair value to the extent that observable inputs are not available, thereby allowing for situations in which there is little, if any, market activity for the asset or liability at the measurement date.

(x) Commitments and contingencies

Liabilities for loss contingencies arising from environmental remediation, claims, assessments, litigation, fines, penalties and other sources are recorded when it is probable that a liability has been incurred and the amount can be reasonably estimated. Legal costs incurred in connection with loss contingencies are expensed as incurred.

(y) Use of estimates

The preparation of financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of these consolidated financial statements and the reported amounts of revenue and expenses during the year. Actual results could differ from those estimates. During the years presented, management has made a number of estimates and valuation assumptions, including the useful lives and recoverability of property, plant and equipment, intangible assets and goodwill; the recoverability of notes receivable and long-term investments; the measurement of deferred taxes and the recoverability of deferred tax assets; assessments of unbilled revenue; pension and OPEB obligations; timing effect of regulated assets and liabilities; contingencies related to environmental matters; the fair value of assets and liabilities acquired in a business combination; and, the fair value of financial instruments. These estimates and valuation assumptions are based on present conditions and management's planned course of action, as well as assumptions about future business and economic conditions. Should the underlying valuation assumptions and estimates change, the recorded amounts could change by a material amount.

2. Recently issued accounting pronouncements

(a) Recently adopted accounting pronouncements

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

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

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

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

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

(b) Recently issued accounting guidance not yet adopted

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

The FASB issued ASU 2017-12, Derivatives and Hedging (Topic 815): Targeted Improvements to Accounting for Hedging Activities, to improve the financial reporting of hedging relationships to better portray the economic results of an entity's risk management activities in its financial statements. The update also makes certain targeted improvements to simplify the application of the hedge accounting guidance. The update is effective for fiscal years beginning after December 15, 2018, and interim periods within those fiscal years. Early application is permitted in any interim period after issuance of the update. The Company is currently assessing the impacts of this update. The Company expects to early adopt this update on January 1, 2018.

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

2. Recently issued accounting pronouncements (continued)

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

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

The FASB issued ASU 2017-05 Other Income—Gains and Losses from the Derecognition of Nonfinancial Assets (Subtopic 610-20): Clarifying the Scope of Asset Derecognition Guidance and Accounting for Partial Sales of Nonfinancial Assets. The update clarifies the scope of the standard as well as provides additional guidance on partial sales of nonfinancial assets. The update is effective for fiscal years and interim periods beginning after December 15, 2017. Early adoption is permitted however the update must be adopted at the same time as ASU 2014-09. No impact on the consolidated financial statements is expected from the adoption of this update.

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

The FASB issued ASU 2017-01 Business Combinations (Topic 805): Clarifying the Definition of a Business. The update is intended to clarify the definition of a business with the objective of adding guidance to assist entities with evaluating whether transactions should be accounted for as acquisitions (or disposals) of assets or businesses. The standard is effective for fiscal years and interim periods beginning after December 15, 2017. The amendments in the Update should be applied prospectively. The Company will follow the pronouncements of this Update after the effective date.

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

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

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

2. Recently issued accounting pronouncements (continued)

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

The FASB issued ASU 2016-13, Financial Instruments - Credit Losses (Topic 326): Measurement of Credit Losses on Financial Instruments to provide financial statement users with more decision-useful information about the expected credit losses on financial instruments and other commitments to extend credit held by a reporting entity at each reporting date. To achieve this objective, the amendments in this update replace the incurred loss impairment methodology in current GAAP with a methodology that reflects expected credit losses. The standard is effective for fiscal years and interim periods beginning after December 15, 2019. Early adoption for fiscal years and interim periods beginning after December 15, 2018 is permitted. The Company is currently in the process of evaluating the impact of adoption of this standard on its consolidated financial statements. The Company does not expect a significant impact on its consolidated financial statements as a result of the adoption of this Update.

The FASB issued ASU 2016-02, Leases (Topic 842) to increase transparency and comparability among organizations utilizing leases. This ASU requires lessees to recognize the assets and liabilities arising from all leases on the balance sheet, but the effect of leases in the statement of operations and the statement of cash flows is largely unchanged. The FASB issued an amendment to ASC Topic 842 which permits companies to elect an optional transition practical expedient to not evaluate existing land easements under the new standard if the land easements were not previously accounted for under existing lease guidance. The FASB also voted to amend ASC Topic 842 to allow companies to elect not to restate their comparative periods in the period of adoption when transitioning to the standard. The standard is effective for fiscal years and interim periods beginning after December 15, 2018. Early adoption is permitted.

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

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

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

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

(in thousands of Canadian dollars, except as noted and per share amounts)

3. Business acquisitions and development projects

(a) Acquisition of Empire

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

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

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

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

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

Goodwill represents the excess of the purchase price over the aggregate fair value of net assets acquired. The contributing factors to the amount recorded as goodwill include future growth, potential synergies and cost savings in the delivery of certain shared administrative and other services. Goodwill is reported under the Liberty Utilities Group segment.

Property, plant and equipment, exclusive of computer software, are amortized in accordance with regulatory requirements over the estimated useful life of the assets using the straight-line method. The weighted average useful life of the Empire's assets is 39 years.

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

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

3. Business acquisitions and development projects (continued)

(a) Acquisition of Empire (continued)

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

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

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

(c) Great Bay Solar Project

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

The Great Bay Solar Facility is controlled by a subsidiary of APUC (Great Bay Holdings, LLC). Approximately U.S. $59,000 of the permanent project financing will come from tax equity investors. Equity capital contribution of U.S. $42,750 was received in 2017 with the remaining expected to be received in early 2018. Through its partnership interest, the tax equity investor will receive the majority of the tax attributes associated with the project. The Company accounts for this interest as "Non-controlling interest" on the consolidated balance sheets.

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

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

(e) Approval to acquire the Perris Water Distribution System

On August 10, 2017 the Company's board approved the acquisition of two water distribution systems serving customers from the City of Perris, California. The anticipated purchase price of U.S. $11,500 is expected to be established as rate base during the regulatory approval process. The City of Perris residents voted to approve the sale on November 7, 2017. Liberty Utilities expects to file the advice letter to acquire the water utility with the California Public Utility Commission in Q1 2018 with approval expected in late 2018.

(f) Luning Solar Facility

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

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

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

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

(g) Bakersfield II Solar Facility

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

The Bakersfield II Solar Facility is controlled by a subsidiary of APUC (the "Bakersfield II Partnership"). The Class A partnership units are owned by a third-party tax equity investor who funded U.S. $2,454 on November 29, 2016 and approximately U.S. $9,800 on February 28, 2017. With its partnership interest, the tax equity investor will receive the majority of the tax attributes associated with the project. The Company accounts for this interest as "Non-controlling interest" on the consolidated balance sheets.

(h) Wind Turbine Components Purchase

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

(i) Acquisition of Park Water System

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

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

(in thousands of Canadian dollars, except as noted and per share amounts)

3. Business acquisitions and development projects (continued)

(i) Acquisition of Park Water System (continued)

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

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

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

Goodwill represents the excess of the purchase price over the aggregate fair value of net assets acquired. The contributing factors to the amount recorded as goodwill include future growth, potential synergies and cost savings in the delivery of certain shared administrative and other services. Goodwill is reported under the Liberty Utilities Group segment.

Property, plant and equipment are amortized in accordance with regulatory requirements over the estimated useful life of the assets using the straight-line method. The weighted average useful life of the Park Water System assets is 40 years.

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

4. Accounts receivable

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

(in thousands of Canadian dollars, except as noted and per share amounts)

5. Property, plant and equipment

Property, plant and equipment consist of the following:

2017

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

2016

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

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

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

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

6. Intangible assets and goodwill

Intangible assets consist of the following:

2017

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

(in thousands of Canadian dollars, except as noted and per share amounts)

6. Intangible assets and goodwill (continued)

2016

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

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

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

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

7. Regulatory matters

The Company's regulated utility operating companies are subject to regulation by the public utility commissions of the states in which they operate. The respective public utility commissions have jurisdiction with respect to rate, service, accounting policies, issuance of securities, acquisitions and other matters. These utilities operate under cost-of-service regulation as administered by these state authorities. The Company's regulated utility operating companies are accounted for under the principles of ASC 980. Under ASC 980, regulatory assets and liabilities that would not be recorded under U.S. GAAP for non-regulated entities are recorded to the extent that they represent probable future revenue or expenses associated with certain charges or credits that will be recovered from or refunded to customers through the rate-setting process.

On January 1, 2017, the Company completed the acquisition of Empire, an operating public utility engaged in the generation, purchase, transmission, distribution and sale of electricity in parts of Missouri, Kansas, Oklahoma and Arkansas. Empire also provides regulated water utility distribution services to three towns in Missouri. The Empire District Gas Company, a wholly owned subsidiary, is engaged in the distribution of natural gas in Missouri. These businesses are subject to regulation by the Missouri Public Service Commission, the State Corporation Commission of the State of Kansas, the Corporation Commission of Oklahoma, the Arkansas Public Service Commission and the Federal Energy Regulatory Commission. In general, the commissions set rates at a level that allows the utilities to collect total revenues or revenue requirements equal to the cost of providing service, plus an appropriate return on invested capital.

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

(in thousands of Canadian dollars, except as noted and per share amounts)

7. Regulatory matters (continued)

Regulatory assets and liabilities consist of the following:

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

(a) Environmental remediation

Actual expenditures incurred for the clean-up of certain former gas manufacturing facilities (note 13(b)) are recovered through rates over a period of 7 years and are subject to an annual cap.

(b) Pension and post-employment benefits

As part of certain business acquisitions, the regulators authorized a regulatory asset or liability being set up for the amounts of pension and post-employment benefits that have not yet been recognized in net periodic cost and were presented as AOCI prior to the acquisition. An amount of U.S. $21,626 relates to an acquisition and was authorized for recognition as an asset by the regulator. Recovery is anticipated to be approved in a final rate order to be received on completion of the next general rate case. The balance is recovered through rates over the future service years of the employees at the time the regulatory asset was set up (an average of 10 years) or consistent with the treatment of OCI under ASC 712 Compensation Non-retirement Post-employment Benefits and ASC 715 Compensation Retirement Benefits before the transfer to regulatory asset occurred. The pension and post-employments benefits liability is related to tracking accounts pertaining primarily to Park Water Company. The amounts recorded in these accounts occur when actual expenses have been less than adopted and refunds are expected to occur in future periods.

7. Regulatory matters (continued)

(c) Debt premium

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

(d) Fuel and commodity costs adjustment

The revenue from the utilities includes a component which is designed to recover the cost of electricity and natural gas through rates charged to customers. To the extent actual costs of power or natural gas purchased differ from power or natural gas costs recoverable through current rates, that difference is not recorded on the consolidated statements of operations but rather is deferred and recorded as a regulatory asset or liability on the consolidated balance sheets. These differences are reflected in adjustments to rates and recorded as an adjustment to cost of electricity and natural gas in future periods, subject to regulatory review. Derivatives are often utilized to manage the price risk associated with natural gas purchasing activities in accordance with the expectations of state regulators. The gains and losses associated with these derivatives (note 25(b)(i)) are recoverable through the commodity costs adjustment.

(e) Rate adjustment mechanism

Revenue for Calpeco Electric System, Park Water System, Peach State Gas System and New England Gas Systems are subject to a revenue decoupling mechanism approved by their respective regulator which require charging approved annual delivery revenue on a systematic basis over the fiscal year. As a result, the difference between delivery revenue calculated based on metered consumption and approved delivery revenue is recorded as a regulatory asset or liability to reflect future recovery or refund, respectively, from customers. In addition, retroactive rate adjustments for services rendered but to be collected over a period not exceeding 24 months are accrued upon approval of the Final Order.

(f) Clean Energy and other customer programs

The regulatory asset for Clean Energy and customer programs includes initiatives related to solar rebate applications processed and resulting rebate-related costs. The amount also includes other energy efficiency programs.

(g) Deferred construction costs

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

(h) Asset retirement

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

(i) Income taxes

The income taxes regulatory assets and liabilities represent income taxes recoverable through future revenues required to fund flow-through deferred income tax liabilities and amounts owed to customers for deferred taxes collected at a higher rate than the current statutory rates.

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

(j) Rate case costs

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

(k) Cost of removal

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

(l) Rate-base offset

The regulators imposed a rate-base offset that will reduce the revenue requirement at future rate proceedings. The rate-base offset declines on a straight-line basis over a period of 10-16 years.

(in thousands of Canadian dollars, except as noted and per share amounts)

7. Regulatory matters (continued)

(m) Deferred compensation received in relation to lost production

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

As recovery of regulatory assets is subject to regulatory approval, if there were any changes in regulatory positions that indicate recovery is not probable, the related cost would be charged to earnings in the period of such determination. The Company generally earns carrying charges on the regulatory balances related to commodity cost adjustment, retroactive rate adjustments and rate case costs.

8. Long-term investments

Long-term investments consist of the following:

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

(a) Red Lily I Wind Facility

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

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

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

(in thousands of Canadian dollars, except as noted and per share amounts)

8. Long-term investments (continued)

(b) Deerfield Wind Project

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

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

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

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

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

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

(c) Amherst Island Wind Project

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

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

(in thousands of Canadian dollars, except as noted and per share amounts)

8. Long-term investments (continued)

(c) Amherst Island Wind Project (continued)

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

(d) Development loans

The Company entered into committed loan and credit support facilities with some of its equity investees. During construction, the Company is obligated to provide cash advances and credit support (in the form of letters of credit, escrowed cash, or guarantees) in amounts necessary for the continued development and construction of the equity investees' wind projects.

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

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

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

(e) 2016 transactions

i. Odell Wind Facility

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

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

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

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

ii. Natural gas pipeline developments

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

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

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

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

Recent financing activities:

(a) Senior unsecured revolving credit facilities

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

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

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

9. Long-term debt (continued)

(a) Senior unsecured revolving credit facilities (continued)

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

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

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

(b) Senior unsecured bank credit facilities

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

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

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

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

(c) Commercial Paper

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

(d) Canadian dollar senior unsecured notes

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

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

(e) U.S. dollar senior unsecured notes

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

(in thousands of Canadian dollars, except as noted and per share amounts)

9. Long-term debt (continued)

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

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

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

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

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

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

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

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

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

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

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

10. Pension and other post-employment benefits

The Company provides defined contribution pension plans to substantially all of its employees. The Company's contributions for 2017 were $9,387 (2016 - $5,223).

In conjunction with the utility acquisitions, the Company assumes defined benefit pension, supplemental executive retirement plans and OPEB plans for qualifying employees in the related acquired businesses. The legacy plans of the electricity and gas utilities are non-contributory defined pension plans covering substantially all employees of the acquired businesses. Benefits are based on each employee's years of service and compensation. The Company also provides a defined benefit cash balance pension plan covering substantially all its new employees and current employees at its water utilities, under which employees are credited with a percentage of base pay plus a prescribed interest rate credit. During 2016, the Company permanently froze the accrual of retirement benefits for participants under certain existing plans. Subsequent to the effective date, these employees began accruing benefits under the Company's cash balance plan. The OPEB plans provide health care and life insurance coverage to eligible retired employees. Eligibility is based on age and length of service requirements and, in most cases, retirees must cover a portion of the cost of their coverage.

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

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

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

(in thousands of Canadian dollars, except as noted and per share amounts)

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

(a) Net pension and OPEB obligation (continued)

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

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

(b) Assumptions

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

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

(in thousands of Canadian dollars, except as noted and per share amounts)

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

(b) Assumptions (continued)

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

	Pension benefits		OPEB	
	2017	**2016**	**2017**	**2016**
Discount rate	**3.43%**	3.95%	**3.60%**	4.04%
Rate of compensation increase	**3.00%**	3.00%	**N/A**	N/A
Health care cost trend rate				
Before Age 65			**6.25%**	6.25%
Age 65 and after			**6.25%**	6.25%
Assumed Ultimate Medical Inflation Rate			**4.75%**	4.75%
Year in which Ultimate Rate is reached			**2024**	2023

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

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

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

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

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

(in thousands of Canadian 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 costs for the pension plans and OPEB recorded as part of operating expenses in the consolidated statements of operations. The employee benefit costs related to businesses acquired are recorded in the consolidated statements of operations from the date of acquisition.

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

(d) Plan assets

The Company's investment strategy for its pension and post-employment plan assets is to maintain a diversified portfolio of assets with the primary goal of meeting long-term cash requirements as they become due.

The Company's target asset allocation is as follows:

Asset Class	Target (%)	Range (%)
Equity securities	70%	49% - 79%
Debt securities	30%	21% - 51%
Other	—%	—%

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

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

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

(e) Cash flows

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

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

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

(in thousands of Canadian dollars, except as noted and per share amounts)

11. Mandatorily redeemable Series C preferred shares

APUC has 100 redeemable Series C preferred shares issued and outstanding. Thirty-six of the Series C preferred shares are owned by related parties controlled by executives of the Company. The preferred shares are mandatorily redeemable in 2031 for $53,400 per share (fifty-three thousand and four hundred dollars per share) and have a contractual cumulative cash dividend paid quarterly until the date of redemption based on a prescribed payment schedule indexed in proportion to the increase in CPI over the term of the shares. The Series C preferred shares are convertible into common shares at the option of the holder and the Company, at any time after May 20, 2031 and before June 19, 2031, at a conversion price of $53,400 per share.

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

Estimated dividend payments due in the next five years and dividend and redemption payments thereafter are:	
2018	$ 1,068
2019	1,282
2020	1,344
2021	1,364
2022	1,390
Thereafter to 2031	15,761
Redemption amount	5,340
	27,549
Less amounts representing interest	(9,085)
	18,464
Less current portion	(1,068)
	$ 17,396

12. Other assets

Other assets consist of the following:

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

(in thousands of Canadian dollars, except as noted and per share amounts)

13. Other long-term liabilities and deferred credits

Other long-term liabilities consist of the following:

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

(a) Advances in aid of construction

The Company's regulated utilities have various agreements with real estate development companies (the "developers") conducting business within the Company's utility service territories, whereby funds are advanced to the Company by the developers to assist with funding some or all of the costs of the development.

In many instances, developer advances can be subject to refund but the refund is non-interest bearing. Refunds of developer advances are made over periods generally ranging from 5 to 40 years. Advances not refunded within the prescribed period are usually not required to be repaid. After the prescribed period has lapsed, any remaining unpaid balance is transferred to contributions in aid of construction and recorded as an offsetting amount to the cost of property, plant and equipment. In 2017, $13,626 (2016 - $23,986) was transferred from advances in aid of construction to contributions in aid of construction.

(b) Environmental remediation obligation

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

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

Changes in the environmental remediation obligation are as follows:

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

By rate orders, the Regulator provided for the recovery of actual expenditures for site investigation and remediation over a period of 7 years and accordingly, as of December 31, 2017, the Company has reflected a regulatory asset of $103,761 (2016 - $104,160) for the MGP and related sites (note 7(a)).

(in thousands of Canadian dollars, except as noted and per share amounts)

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

(c) Asset retirement obligations

Asset retirement obligations mainly relate to legal requirements to: (i) remove wind farm facilities upon termination of land leases; (ii) cut (disconnect from the distribution system), purge (cleanup of natural gas and Polychlorinated Biphenyls "PCB" contaminants) and cap gas mains within the gas distribution and transmission system when mains are retired in place, or sections of gas main are removed from the pipeline system; (iii) clean and remove storage tanks containing waste oil and other waste contaminants; (iv) remove certain river water intake structures and equipment; (v) disposal of coal combustion residuals and PCB contaminants and (vi) remove asbestos upon major renovation or demolition of structures and facilities. During the year, APUC assumed asset retirement obligations in connection with the acquisitions of Empire (note 3(a)) and Deerfield SponsorCo (note 8(b)) of $31,717 and $2,816, respectively, recorded additional asset retirement obligations for renewable generation facilities being constructed of $2,604 (2016 - $393), changes in estimates of $1,476 (2016 - $1,022), accretion expense of $2,551 (2016 - $1,055) and settlements of $5,418 (2016 - $nil).

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

(d) Customer deposits

Customer deposits result from the Company's obligation by state regulators to collect a deposit from customers of its facilities under certain circumstances when services are connected. The deposits are refundable as allowed under the facilities' regulatory agreement.

(e) Unamortized investment tax credits

The unamortized investment tax credits were assumed in connection with the acquisition of Empire. The investment tax credits are associated with an investment made in a generating station. The credits are being amortized over the life of the generating station.

(f) Deferred credits

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

14. Convertible Unsecured Subordinated Debentures

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

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

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

(in thousands of Canadian dollars, except as noted and per share amounts)

14. Convertible Unsecured Subordinated Debentures (continued)

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

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

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

15. Shareholders' capital

(a) Common shares

Number of common shares:

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

Authorized

APUC is authorized to issue an unlimited number of common shares. The holders of the common shares are entitled to dividends if, as and when declared by the Board of Directors (the "Board"); to one vote per share at meetings of the holders of common shares; and upon liquidation, dissolution or winding up of APUC to receive pro rata the remaining property and assets of APUC, subject to the rights of any shares having priority over the common shares.

The Company has a shareholders' rights plan (the "Rights Plan") which expires in 2019. Under the Rights Plan, one right is issued with each issued share of the Company. The rights remain attached to the shares and are not exercisable or separable unless one or more certain specified events occur. If a person or group acting in concert acquires 20 percent or more of the outstanding shares (subject to certain exceptions) of the Company, the rights will entitle the holders thereof (other than the acquiring person or group) to purchase shares at a 50 percent discount from the then current market price. The rights provided under the Rights Plan are not triggered by any person making a "Permitted Bid", as defined in the Rights Plan.

(i) Public offering

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

(ii) Subscription receipts

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

(in thousands of Canadian dollars, except as noted and per share amounts)

15. Shareholders' capital (continued)

(a) Common shares (continued)

(ii) Subscription receipts (continued)

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

(iii) Dividend reinvestment plan

The Company has a common shareholder dividend reinvestment plan, which provides an opportunity for shareholders to reinvest dividends for the purpose of purchasing common shares. Additional common shares acquired through the reinvestment of cash dividends are purchased in the open market or are issued by APUC at a discount of up to 5% from the average market price, all as determined by the Company from time to time. Subsequent to year-end, APUC issued an additional 1,063,572 common shares under the dividend reinvestment plan.

(b) Preferred shares

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

The Company has the following Series A and Series D preferred shares issued and outstanding as at December 31, 2017 and 2016:

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

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

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

The Company has 100 redeemable Series C preferred shares issued and outstanding. The mandatorily redeemable Series C preferred shares are recorded as a liability on the consolidated balance sheets as they are mandatorily redeemable for cash (note 11).

(in thousands of Canadian dollars, except as noted and per share amounts)

15. Shareholders' capital (continued)

(c) Share-based compensation

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

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

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

As of December 31, 2017, total unrecognized compensation costs related to non-vested options and PSUs were $2,796 and $8,471, respectively, and are expected to be recognized over a period of 1.61 and 1.84 years, respectively.

(i) Share option plan

The Company's share option plan (the "Plan") permits the grant of share options to key officers, directors, employees and selected service providers. The aggregate number of shares that may be reserved for issuance under the Plan must not exceed 8% of the number of shares outstanding at the time the options are granted.

The number of shares subject to each option, the option price, the expiration date, the vesting and other terms and conditions relating to each option shall be determined by the Board from time to time. Dividends on the underlying shares do not accumulate during the vesting period. Option holders may elect to surrender any portion of the vested options which is then exercisable in exchange for the "In-the-Money Amount". In accordance with the Plan, the "In-The-Money Amount" represents the excess, if any, of the market price of a share at such time over the option price, in each case such "In-the-Money Amount" being payable by the Company in cash or shares at the election of the Company. As the Company does not expect to settle these instruments in cash, these options are accounted for as equity awards.

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

In the event that the Company restates its financial results, any unpaid or unexercised options may be cancelled at the discretion of the Board (or the compensation committee of the Board ("Compensation Committee")) in accordance with the terms of the Company's clawback policy.

The estimated fair value of options, including the effect of estimated forfeitures, is recognized as expense on a straight-line basis over the options' vesting periods while ensuring that the cumulative amount of compensation cost recognized at least equals the value of the vested portion of the award at that date. The Company determines the fair value of options granted using the Black-Scholes option-pricing model. The risk-free interest rate is based on the zero-coupon Canada Government bond with a similar term to the expected life of the options at the grant date. Expected volatility was estimated based on the adjusted historical volatility of the Company's shares. The expected life was based on experience to-date. The dividend yield rate was based upon recent historical dividends paid on APUC shares.

(in thousands of Canadian dollars, except as noted and per share amounts)

15. Shareholders' capital (continued)

(c) Share-based compensation (continued)

(i) Share option plan (continued)

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

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

Share option activity during the years is as follows:

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

(ii) Employee share purchase plan

Under the Company's employee share purchase plan ("ESPP"), eligible employees may have a portion of their earnings withheld to be used to purchase the Company's common shares. The Company will match (a) 20% of the employee contribution amount for the first five thousand dollars per employee contributed annually and 10% of the employee contribution amount for contributions over five thousand dollars up to ten thousand dollars annually, for Canadian employees, and (b) 15% of the employee contribution amount for the first fifteen thousand dollar per employee contributed annually, for U.S. employees. Common shares purchased through the Company match portion shall not be eligible for sale by the participant for a period of one year following the contribution date on which such shares were acquired. At the Company's option, the common shares may be (i) issued to participants from treasury at the average share price or (ii) acquired on behalf of participants by purchases through the facilities of the TSX by an independent broker. The aggregate number of common shares reserved for issuance from treasury by APUC under the ESPP shall not exceed 2,000,000 common shares.

The Company uses the fair value based method to measure the compensation expense related to the Company's contribution. For the year ended December 31, 2017, a total of 283,523 common shares (2016 - 144,264) were issued to employees under the ESPP.

(in thousands of Canadian dollars, except as noted and per share amounts)

15. Shareholders' capital (continued)

(c) Share-based compensation (continued)

(iii) Directors deferred share units

Under the Company's Deferred Share Unit Plan, non-employee directors of the Company may elect annually to receive all or any portion of their compensation in DSUs in lieu of cash compensation. Directors' fees are paid on a quarterly basis and at the time of each payment of fees, the applicable amount is converted to DSUs. A DSU has a value equal to one of the Company's common shares. Dividends accumulate in the DSU account and are converted to DSUs based on the market value of the shares on that date. DSUs cannot be redeemed until the director retires, resigns, or otherwise leaves the Board. The DSUs provide for settlement in cash or shares at the election of the Company. As the Company does not expect to settle these instruments in cash, these options are accounted for as equity awards. As of December 31, 2017, 293,906 (2016 - 224,663) DSUs were outstanding pursuant to the election of the directors to defer a percentage of their director's fee in the form of DSUs. The aggregate number of common shares reserved for issuance from treasury by APUC under the DSU Plan shall not exceed 1,000,000 common shares.

(iv) Performance share units

The Company offers a PSU plan to its employees as part of the Company's long-term incentive program. PSUs are granted annually for three-year overlapping performance cycles. PSUs vest at the end of the three-year cycle and will be calculated based on established performance criteria. At the end of the three-year performance periods, the number of common shares issued can range from 2.0% to 237% of the number of PSUs granted. Dividends accumulating during the vesting period are converted to PSUs based on the market value of the shares on that date and are recorded in equity as the dividends are declared. None of these PSUs have voting rights. Any PSUs not vested at the end of a performance period will expire. The PSUs provide for settlement in cash or shares at the election of the Company. As the Company does not expect to settle these instruments in cash, these options are accounted for as equity awards. The aggregate number of common shares reserved for issuance from treasury by APUC under the PSU Plan shall not exceed 7,000,000 common shares.

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

A summary of the PSUs follows:

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

(in thousands of Canadian dollars, except as noted and per share amounts)

16. Accumulated Other comprehensive income (loss)

AOCI consists of the following balances, net of tax:

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

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

17. Dividends

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

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

18. Related party transactions

Emera Inc.

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

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

(in thousands of Canadian dollars, except as noted and per share amounts)

18. Related party transactions (continued)

Equity-method investments

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

Trafalgar

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

Long Sault Hydro Facility

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

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

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

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

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

The non-controlling Class A membership equity investors ("Class A partnership units") in the Company's U.S. wind power and solar power generating facilities are entitled to allocations of earnings, tax attributes and cash flows in accordance with contractual agreements. The share of earnings attributable to the non-controlling interest holders in these subsidiaries is calculated using the HLBV method of accounting as described in note 1(r).

The terms of the arrangement refer to the tax rate in effect when the benefits are delivered. As such, The U.S. federal corporate tax rate of 35% was used to calculate HLBV as at December 31, 2017. The reduced U.S. federal corporate tax rate of 21% and other certain measures discussed in note 20 will be used in the calculation of HLBV beginning in 2018.

Non-controlling interest

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

(in thousands of Canadian dollars, except as noted and per share amounts)

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

Redeemable Non-controlling interest

Non-controlling interests in subsidiaries that are redeemable upon the occurrence of uncertain events not solely within APUC's control are classified as temporary equity on the consolidated balance sheets. The redeemable non-controlling interests in subsidiaries balance is determined using the hypothetical liquidation at book value method subsequent to initial recognition, however, if the redemption amount is probable or currently redeemable, the Company records the instruments at their redemption value. Redemption is not considered probable as of December 31, 2017. Changes in redeemable non-controlling interest are as follows:

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

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

20. Income taxes

The provision for income taxes in the consolidated statements of operations represents an effective tax rate different than the Canadian enacted statutory rate of 26.5% (2016 - 26.5%). The differences are as follows:

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

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

(in thousands of Canadian dollars, except as noted and per share amounts)

20. Income taxes (continued)

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

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

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

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

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

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

(in thousands of Canadian dollars, except as noted and per share amounts)

20. Income taxes (continued)

The tax effect of temporary differences between the financial statement carrying amounts of assets and liabilities and their respective tax bases that give rise to significant portions of the deferred tax assets and deferred tax liabilities as of December 31, 2017 and 2016 are presented below:

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

The valuation allowance for deferred tax assets as at December 31, 2017 was $15,486 (2016 - $21,656). The valuation allowance primarily relates to operating losses that, in the judgment of management, are not more likely than not to be realized. In assessing the realizability of deferred tax assets, management considers whether it is more likely than not that some portion or all of the deferred tax assets will not be realized. The ultimate realization of deferred tax assets is dependent upon the generation of future taxable income during the periods in which those temporary differences become deductible. Management considers the scheduled reversal of deferred tax liabilities (including the impact of available carryback and carryforward periods), projected future taxable income, and tax-planning strategies in making this assessment.

As of December 31, 2017, the Company had non-capital losses carried forward available to reduce future year's taxable income, which expire as follows:

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

The Company has provided for deferred income taxes for the estimated tax cost of distributed earnings of its subsidiaries. Deferred income taxes have not been provided on approximately $188,348 of undistributed earnings of certain foreign subsidiaries, as the Company has concluded that such earnings are indefinitely reinvested and should not give rise to additional tax liabilities. A determination of the amount of the unrecognized tax liability relating to the remittance of such undistributed earnings is not practicable.

(in thousands of Canadian dollars, except as noted and per share amounts)

21. Basic and diluted net earnings per share

Basic and diluted earnings per share have been calculated on the basis of net earnings attributable to the common shareholders of the Company and the weighted average number of common shares and subscription receipts outstanding (note 15 (a)). Diluted net earnings per share is computed using the weighted-average number of common shares, subscription receipts outstanding, additional shares issued subsequent to year-end under the dividend reinvestment plan, PSUs and DSUs outstanding during the year and, if dilutive, potential incremental common shares resulting from the application of the treasury stock method to outstanding share options. The convertible debentures (note 14) are convertible into common shares at any time after the Final Instalment Date, but prior to maturity or redemption by the Company. The Final Instalment Date occurred on February 2, 2017, and as such, the shares issuable upon conversion of the convertible debentures are included in diluted earnings per share beginning on that date.

The reconciliation of the net earnings and the weighted average shares used in the computation of basic and diluted earnings per share are as follows:

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

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

(in thousands of Canadian dollars, except as noted and per share amounts)

22. Segmented information

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

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

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

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

(in thousands of Canadian dollars, except as noted and per share amounts)

22. Segmented information (continued)

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

The majority of non-regulated energy sales are earned from contracts with large public utilities. The Company has mitigated its credit risk to the extent possible by selling energy to large utilities in various North American locations. None of the utilities contribute more than 10% of total revenue.

APUC operates in the independent power and utility industries in both Canada and the United States. Information on operations by geographic area is as follows:

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

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

(in thousands of Canadian dollars, except as noted and per share amounts)

23. Commitments and contingencies

(a) Contingencies

APUC and its subsidiaries are involved in various claims and litigation arising out of the ordinary course and conduct of its business. Although such matters cannot be predicted with certainty, management does not consider APUC's exposure to such litigation to be material to these financial statements. Accruals for any contingencies related to these items are recorded in the consolidated financial statements at the time it is concluded that its occurrence is probable and the related liability is estimable.

Condemnation Expropriation Proceedings

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

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

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

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

(b) Commitments

In addition to the commitments related to the proposed acquisitions and development projects disclosed in notes 3 and 8, the following significant commitments exist as of December 31, 2017.

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

Detailed below are estimates of future commitments under these arrangements:

	Year 1	Year 2	Year 3	Year 4	Year 5	Thereafter	Total
Power purchase (i)	$ 74,025	$ 48,344	$ 49,940	$ 50,214	$ 50,495	$ 254,380	$ 527,398
Gas supply and service agreements (ii)	91,425	66,848	51,809	33,161	28,411	97,489	369,143
Service agreements	47,695	47,211	48,529	48,827	46,548	435,093	673,903
Capital projects	41,054	17,064	65	65	65	16	58,329
Operating leases	9,573	8,974	8,298	8,361	9,718	225,047	269,971
Total	$263,772	$188,441	$158,641	$140,628	$135,237	$ 1,012,025	$ 1,898,744

(in thousands of Canadian dollars, except as noted and per share amounts)

23. Commitments and contingencies (continued)

(b) Commitments (continued)

(i) Power purchase: APUC's electric distribution facilities have commitments to purchase physical quantities of power for load serving requirements. The commitment amounts included in the table above are based on market prices as of December 31, 2017. However, the effects of purchased power unit cost adjustments are mitigated through a purchased power rate-adjustment mechanism.

(ii) Gas supply and service agreements: APUC's gas distribution facilities and thermal generation facilities have commitments to purchase physical quantities of natural gas under contracts for purposes of load serving requirements and of generating power.

24. Non-cash operating items

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

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

(in thousands of Canadian dollars, except as noted and per share amounts)

25. Financial instruments

(a) Fair value of financial instruments

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

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

(in thousands of Canadian dollars, except as noted and per share amounts)

25. Financial instruments (continued)

(a) Fair value of financial instruments (continued)

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

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

(in thousands of Canadian dollars, except as noted and per share amounts)

25. Financial instruments (continued)

(a) Fair value of financial instruments (continued)

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

Notes receivable fair values (level 2) have been determined using a discounted cash flow method, using estimated current market rates for similar instruments adjusted for estimated credit risk as determined by management.

The Company's level 2 fair value of long-term debt at fixed interest rates and Series C preferred shares has been determined using a discounted cash flow method and current interest rates.

The Company's level 2 fair value derivative instruments primarily consist of swaps, options, rights and forward physical deals where market data for pricing inputs are observable. Level 2 pricing inputs are obtained from various market indices and utilize discounting based on quoted interest rate curves which are observable in the marketplace. Transmission congestion rights positions are fair valued using the most recent monthly auction clearing prices.

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

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

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

(b) Derivative instruments

Derivative instruments are recognized on the consolidated balance sheets as either assets or liabilities and measured at fair value at each reporting period.

(i) Commodity derivatives – regulated accounting

The Company uses derivative financial instruments to reduce the cash flow variability associated with the purchase price for a portion of future natural gas purchases associated with its regulated gas and electric service territories. The Company's strategy is to minimize fluctuations in gas sale prices to regulated customers.

The following are commodity volumes, in dekatherms ("dths") associated with the above derivative contracts:

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

(in thousands of Canadian dollars, except as noted and per share amounts)

25. Financial instruments (continued)

(b) Derivative instruments (continued)

(i) Commodity derivatives – regulated accounting (continued)

The accounting for these derivative instruments is subject to guidance for rate-regulated enterprises. Therefore, the fair value of these derivatives is recorded as current or long-term assets and liabilities, with offsetting positions recorded as regulatory assets and regulatory liabilities in the consolidated balance sheets. Most of the gains or losses on settlement of these contracts are included in the calculation of deferred gas costs (note 7(d)). As a result, the changes in fair value of these natural gas derivative contracts and their offsetting adjustment to regulatory assets and liabilities had no earnings impact.

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

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

(ii) Cash flow hedges

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

Notional quantity (MW-hrs)	Expiry	Receive average prices (per MW-hr)	Pay floating price (per MW-hr)
688,147	December 2023	U.S. $ 40.40	PJM Western HUB
2,926,922	December 2023	U.S. $ 29.26	NI HUB
3,330,876	December 2027	U.S. $ 36.46	ERCOT North HUB

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

The Company is party to a 10-year forward-starting interest rate swap beginning on July 25, 2018 in order to reduce the interest rate risk related to the probable issuance on that date of a 10-year $135,000 bond. The change in fair value resulted in a gain of $2,771 for the year ended December 31, 2017 (2016 - loss of $3,726), which is recorded in OCI.

(in thousands of Canadian dollars, except as noted and per share amounts)

25. Financial instruments (continued)

(b) Derivative instruments (continued)

(ii) Cash flow hedges (continued)

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

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

The Company expects $11,612 and $2,643 of unrealized gains currently in AOCI to be reclassified, net of taxes into non-regulated energy sales and interest expense, respectively, within the next twelve months, as the underlying hedged transactions settle.

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

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

The Company designates the amounts drawn on the Liberty Power Group's revolving credit facility denominated in U.S. dollars in excess of the principal amount on the USD loans receivable from its equity investees as a hedge of the foreign currency exposure of its net investment in the Liberty Power Group's U.S. operations. The related foreign currency transaction gain or loss designated as, and effective as, a hedge of the net investment in a foreign operation are reported in the same manner as the translation adjustment (in OCI) related to the net investment. A foreign currency gain of $21,648 for the year ended December 31, 2017 (2016 - nil) was recorded in OCI.

Concurrent with its $150,000, $200,000 and $300,000 debenture offerings in December 2012, January 2014, and January 2017, respectively, the Company entered into cross currency swaps, coterminous with the debentures, to effectively convert the Canadian dollar denominated offering into U.S. dollars. The Company designated the entire notional amount of the cross currency fixed-for-fixed interest rate swap and related short-term U.S. dollar payables created by the monthly accruals of the swap settlement as a hedge of the foreign currency exposure of its net investment in the Liberty Power Group's U.S. operations. The gain or loss related to the fair value changes of the swap and the related foreign currency gains and losses on the U.S. dollar accruals that are designated as, and are effective as, a hedge of the net investment in a foreign operation are reported in the same manner as the translation adjustment (in OCI) related to the net investment. A gain of $23,381 (2016 - $6,156) was recorded in OCI in 2017.

(iv) Other derivatives

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

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

(in thousands of Canadian dollars, except as noted and per share amounts)

25. Financial instruments (continued)

(b) Derivative instruments (continued)

(iv) Other derivatives (continued)

The Company is exposed to interest rate fluctuations related to certain of its floating rate debt obligation, including certain project specific debt and its revolving credit facilities, its interest rate swaps as well as interest earned on its cash on hand. The Company currently hedges some of that risk (note 25(b)(ii)).

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

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

The Company is exposed to foreign exchange fluctuations related to the portion of its dividend declared and payable in U.S. dollars. This risk is mitigated through the use of currency forward contracts. For the year ended December 31, 2017, a loss on foreign exchange of $432 (2016 - $nil) was recorded in the consolidated statements of operations. These currency forward contracts are not accounted for as a hedge.

For derivatives that are not designated as hedges and for the ineffective portion of gains and losses on derivatives that are accounted for as hedges, the changes in the fair value are immediately recognized in earnings.

The effects on the consolidated statements of operations of derivative financial instruments not designated as hedges consist of the following:

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

(in thousands of Canadian dollars, except as noted and per share amounts)

25. Financial instruments (continued)

(c) Risk management

In the normal course of business, the Company is exposed to financial risks that potentially impact its operating results. The Company employs risk management strategies with a view of mitigating these risks to the extent possible on a cost effective basis. Derivative financial instruments are used to manage certain exposures to fluctuations in exchange rates, interest rates and commodity prices. The Company does not enter into derivative financial agreements for speculative purposes.

This note provides disclosures relating to the nature and extent of the Company's exposure to risks arising from financial instruments, including credit risk and liquidity risk, and how the Company manages those risks.

Credit risk

Credit risk is the risk of an unexpected loss if a customer or counterparty to a financial instrument fails to meet its contractual obligations. The Company's financial instruments that are exposed to concentrations of credit risk are primarily cash and cash equivalents, accounts receivable, notes receivable and derivative instruments. The Company limits its exposure to credit risk with respect to cash equivalents by ensuring available cash is deposited with its senior lenders all of which have a credit rating of A or better. The Company does not consider the risk associated with the Liberty Power Group accounts receivable to be significant as over 90% of revenue from power generation is earned from large utility customers having a credit rating of BBB or better, and revenue is generally invoiced and collected within 45 days.

The remaining revenue is primarily earned by the Liberty Utilities Group which consists of water and wastewater, electric and gas utilities in the United States. In this regard, the credit risk related to the Liberty Utilities Group accounts receivable balances of U.S. $204,380 is spread over thousands of customers. The Company has processes in place to monitor and evaluate this risk on an ongoing basis including background credit checks and security deposits from new customers. In addition, the state regulators of the Liberty Utilities Group allow for a reasonable bad debt expense to be incorporated in the rates and therefore recovered from rate payers.

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

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

In addition, the Company continuously monitors the creditworthiness of the counterparties to its foreign exchange, interest rate, and energy derivative contracts prior to settlement, and assesses each counterparty's ability to perform on the transactions set forth in the contracts. The counterparties consist primarily of financial institutions. This concentration of counterparties may impact the Company's overall exposure to credit risk, either positively or negatively, in that the counterparties may be similarly affected by changes in economic, regulatory or other conditions.

Liquidity risk

Liquidity risk is the risk that the Company will not be able to meet its financial obligations as they fall due. The Company's approach to managing liquidity risk is to ensure, to the extent possible, that it will always have sufficient liquidity to meet liabilities when due. As of December 31, 2017, in addition to cash on hand of $54,550 the Company had $1,145,859 available to be drawn on its senior debt facilities. Each of the Company's revolving credit facilities contain covenants which may limit amounts available to be drawn.

(in thousands of Canadian dollars, except as noted and per share amounts)

25. Financial instruments (continued)

(c) Risk management (continued)

Liquidity risk (continued)

The Company's liabilities mature as follows:

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

26. Comparative figures

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

Notes

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, Natural 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
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