UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20509

Form 20-F

(Mark One)

☐ REGISTRATION STATEMENT PURSUANT TO SECTION 12(b) OR (g) OF THE SECURITIES EXCHANGE ACT OF 1934

OR

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

For the fiscal year ended December 31, 2017

OR

☐ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

OR

☐ SHELL COMPANY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

Date of event requiring this shell company report___________
For the transition period from_________to_________.
Commission file number: 001-36487

Atlantica Yield plc

(Exact name of Registrant as specified in its charter)

Not applicable
(Translation of Registrant's name into English)

England and Wales
(Jurisdiction of incorporation or organization)

Great West House, GW1, 17th floor
Great West Road
Brentford, United Kingdom TW8 9DF
Tel: +44 203 499 0465
(Address of principal executive offices)

Santiago Seage
Great West House, GW1, 17th floor
Great West Road
Brentford, United Kingdom TW8 9DF
Tel: +44 203 499 0465

(Name, Telephone, E-mail and/or Facsimile number and Address of Company Contact Person)

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

Title of each class	Name of each exchange on which registered
Ordinary Shares, nominal value $0.10 per share	NASDAQ Global Select Market

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

None

Securities for which there is a reporting obligation pursuant to Section 15(d) of the Act.

None

Indicate the number of outstanding shares of each of the issuer's classes of capital or common stock as of the close of the period covered by the annual report: 100,217,260 ordinary shares, nominal value $0.10 per share.

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. ☒Yes ☐ No

If this report is an annual or transition report, indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934. ☐Yes ☒ No

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. ☒Yes ☐ No

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). ☒Yes ☐ No

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer.

Large accelerated filer ☒	Accelerated filer ☐	Non-accelerated filer ☐

Indicate by check mark which basis of accounting the registrant has used to prepare the financial statements included in this filing:

U.S. GAAP ☐	International Financial Reporting Standards as issued by the International Accounting Standards Board ☒	Other ☐

If "Other" has been checked in response to the previous question indicate by check mark which financial statement item the registrant has elected to follow. ☐ Item 17 ☐ Item 18

If this is an annual report, indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). ☐Yes ☒No

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CAUTIONARY STATEMENTS REGARDING FORWARD-LOOKING STATEMENTS

This annual report includes forward-looking statements. These forward-looking statements include, but are not limited to, all statements other than statements of historical facts contained in this annual report, including, without limitation, those regarding our future financial position and results of operations, our strategy, plans, objectives, goals and targets, future developments in the markets in which we operate or are seeking to operate or anticipated regulatory changes in the markets in which we operate or intend to operate. In some cases, you can identify forward-looking statements by terminology such as "aim," "anticipate," "believe," "continue," "could," "estimate," "expect," "forecast," "guidance," "intend," "is likely to," "may," "plan," "potential," "predict," "projected," "should" or "will" or the negative of such terms or other similar expressions or terminology.

By their nature, forward-looking statements involve risks and uncertainties because they relate to events and depend on circumstances that may or may not occur in the future. Forward-looking statements speak only as of the date of this annual report and are not guarantees of future performance and are based on numerous assumptions. Our actual results of operations, financial condition and the development of events may differ materially from (and be more negative than) those made in, or suggested by, the forward-looking statements. Investors should read the section entitled "Item 3.D—Risk Factors" and the description of our segments and business sectors in the section entitled "Item 4.B—Business Overview" for a more complete discussion of the factors that could affect us. Important risks, uncertainties and other factors that could cause these differences include, but are not limited to:

- Difficult conditions in the global economy and in the global market and uncertainties in emerging markets where we have international operations;
- Changes in government regulations providing incentives and subsidies for renewable energy, including reduction of our revenues in Spain, which are mainly defined by regulation through parameters that could be reviewed at the end of each regulatory period;
- Our ability to acquire solar projects due to the potential increase of the cost of solar panels;
- Political, social and macroeconomic risks relating to the United Kingdom's exit from the European Union;
- Changes in general economic, political, governmental and business conditions globally and in the countries in which we do business;
- Decreases in government expenditure budgets, reductions in government subsidies or adverse changes in laws and regulations affecting our businesses and growth plan;
- Challenges in achieving growth and making acquisitions due to our dividend policy;
- Inability to identify and/or consummate future acquisitions, under the AAGES ROFO Agreement, the Abengoa ROFO Agreement or otherwise, on favorable terms or at all;
- Our ability to identify and reach an agreement with new partners similar to the AAGES ROFO Agreement or Abengoa ROFO Agreement;
- Our ability to identify and/or consummate future acquisitions from third parties or from potential new partners, including as a result of not being able to find acquisition opportunities at attractive prices;
- Legal challenges to regulations, subsidies and incentives that support renewable energy sources; extensive governmental regulation in a number of different jurisdictions, including stringent environmental regulation;
- Increases in the cost of energy and gas, which could increase our operating costs;
- Counterparty credit risk and failure of counterparties to our offtake agreements to fulfill their obligations;

- Inability to replace expiring or terminated offtake agreements with similar agreements;
- New technology or changes in industry standards;
- Inability to manage exposure to credit, interest rates, foreign currency exchange rates, supply and commodity price risks;
- Reliance on third-party contractors and suppliers;
- Risks associated with acquisitions and investments;
- Deviations from our investment criteria for future acquisitions and investments;
- Failure to maintain safe work environments;
- Effects of catastrophes, natural disasters, adverse weather conditions, climate change, unexpected geological or other physical conditions, criminal or terrorist acts or cyber-attacks at one or more of our plants;
- Insufficient insurance coverage and increases in insurance cost;
- Litigation and other legal proceedings including claims due to Abengoa's restructuring process;
- Reputational risk, including damage caused to us by Abengoa's reputation;
- The loss of one or more of our executive officers;
- Failure of information technology on which we rely to run our business;
- Revocation or termination of our concession agreements or power purchase agreements;
- Lowering of revenues in Spain that are mainly defined by regulation;
- Risk that the Share Sale will not be completed and the AAGES ROFO Agreement and Algonquin ROFO Agreement will not become effective;
- Inability to adjust regulated tariffs or fixed-rate arrangements as a result of fluctuations in prices of raw materials, exchange rates, labor and subcontractor costs;
- Exposure to market electricity can impact revenue from our renewable energy and efficient natural gas (previously named "conventional") power facilities;
- Changes to national and international law and policies that support renewable energy resources;
- Lack of electric transmission capacity and potential upgrade costs to the electric transmission grid;
- Disruptions in our operations as a result of our not owning the land on which our assets are located;
- Risks associated with maintenance, expansion and refurbishment of electric generation facilities;
- Failure of our assets to perform as expected, including Solana and Kaxu;
- Failure to receive dividends from all project and investments, including Solana and Kaxu;
- Variations in meteorological conditions;

- Disruption of the fuel supplies necessary to generate power at our efficient natural gas (previously named “conventional”) generation facilities;
- Deterioration in Abengoa’s financial condition;
- Abengoa’s ability to meet its obligations under our agreements with Abengoa, including operation and maintenance agreements, to comply with past representations, commitments and potential liabilities linked to the time when Abengoa owned the assets, potential clawback of transactions with Abengoa, and other risks related to Abengoa;
- Failure to meet certain covenants under our financing arrangements;
- Failure to obtain pending waivers in relation to the minimum ownership by Abengoa and the cross-default provisions contained in some of our project financing agreements;
- Failure of Abengoa to maintain existing guarantees and letters of credit under the Financial Support Agreement or failure by us to maintain guarantees;
- Failure of Abengoa to maintain its obligations and production guarantees, pursuant to EPC contracts;
- Our ability to consummate future acquisitions from AAGES, Algonquin, Abengoa or others;
- Our ability to close acquisitions under our ROFO agreements with AAGES, Algonquin, Abengoa and others due to, among other things, not being offered with assets that fit in our portfolio or not reaching agreements on prices;
- Our ability to use U.S. NOLs to offset future income may be limited, including as the result of experiencing an “ownership change” as defined under Section 382 of the Internal Revenue Code of 1986, as amended (“IRC”);
- Conflicts of interest which may be resolved in a manner that is not in our best interests or the best interests of our minority shareholders, potentially caused by our ownership structure and certain service agreements in place with our current largest shareholder;
- The divergence of interest between us and Abengoa, due to Abengoa’s sale of our shares;
- Potential negative tax implications from an ownership change under section 382 of the Internal Revenue Code;
- Negative implications from a potential change of control;
- Negative implications of U.S. federal income tax reform;
- Impact on our stock price due to the sale by Abengoa of its stake in us and potential negative effects of a potential sale by Abengoa of its stake in us or of a potential change of control or of a potential delay or failure of a sale process;
- Technical failure, design errors or faulty operation of our assets not covered by guarantees or insurance;
- Failure to collect insurance proceeds in the expected amounts;
- Failure to reach an agreement on the extension of the production guarantee period at Solana and Kaxu; and

- Various other factors, including those factors discussed under “Item 3.D—Risk Factors” and “Item 5.A—Operating Results” herein.

We caution that the important factors referenced above may not be all of the factors that are important to investors. Unless required by law, we undertake no obligation to update or revise any forward-looking statement, whether as a result of new information, future events or developments or otherwise.

CURRENCY PRESENTATION AND DEFINITIONS

In this annual report, all references to “U.S. dollar,” “$” and “USD” are to the lawful currency of the United States, all references to “euro,” “€” or “EUR” are to the single currency of the participating member states of the European and Monetary Union of the Treaty Establishing the European Community, as amended from time to time and all references to “South African rand,” “R” and “ZAR” are to the lawful currency of the Republic of South Africa.

Definitions

Unless otherwise specified or the context requires otherwise in this annual report:

- references to “2019 Notes” refer to the 7.000% Senior Notes due 2019 in an aggregate principal amount of $255 million issued on November 17, 2014, as further described in “Item 5.B—Liquidity and Capital Resources—Financing Arrangements—2019 Notes;”
- references to “AAGES” refer to the joint venture between Algonquin and Abengoa to invest in the development and construction of clean energy and water infrastructure contracted assets;
- references to “AAGES ROFO Agreement” refer to the agreement we entered into with AAGES on March 5, 2018, which will become effective upon completion of the Share Sale, that provides us a right of first offer to purchase any of the AAGES ROFO Assets, as amended and restated from time to time;
- references to “AAGES ROFO Assets” refer to any of AAGES’ contracted assets or proposed contracted assets that we expect to evaluate for future acquisition, with certain exceptions, for which AAGES has provided us a right of first offer to purchase if offered for sale by AAGES;
- references to “ACBH” refer to Abengoa Concessões Brasil Holding, a subsidiary holding company of Abengoa that was engaged in the development, construction, investment and management of contracted concessions in Brazil, comprised mostly of transmission lines and which is currently undergoing a restructuring process in Brazil;
- references to “Abengoa” refer to Abengoa, S.A., together with its subsidiaries, unless the context otherwise requires;
- references to “Abengoa ROFO Agreement” refer to the agreement we entered into with Abengoa on June 13, 2014, as amended and restated on December 9, 2014, that provides us a right of first offer to purchase any of the present or future contracted assets in renewable energy, efficient natural gas power, electric transmission and water of Abengoa that are in operation, and any other renewable energy, efficient natural gas power, electric transmission and water asset that is expected to generate contracted revenue and that Abengoa has transferred to an investment vehicle that are located in the United States, Canada, Mexico, Chile, Peru, Uruguay, Brazil, Colombia and the European Union, and four additional assets in other selected regions, including a pipeline of specified assets that we expect to evaluate for future acquisition, for which Abengoa will provide us a right of first offer to purchase if offered for sale by Abengoa or an investment vehicle to which Abengoa has transferred them;
- references to “Algonquin” refer to, as the context requires, either Algonquin Power & Utilities Corp., a North American diversified generation, transmission and distribution utility, together with its subsidiaries;
- references to “Algonquin ROFO Agreement” refer to the agreement we entered into with Algonquin on March 5, 2018, which will become effective upon completion of the Share Sale, under which Algonquin granted us a right of first offer to purchase any of the assets offered for sale located outside of the United States or Canada as amended from time to time. See “Item 7.B—Related Party Transactions—Algonquin drop down agreement and Right of First Offer on assets outside the United States or Canada;”

- references to "Annual Consolidated Financial Statements" refer to the audited annual consolidated financial statements as of December 31, 2017 and 2016 and for the years ended December 31, 2017, 2016 and 2015, including the related notes thereto, prepared in accordance with IFRS as issued by the IASB (as such terms are defined herein), included in this annual report;

- references to "Asset Transfer" refer to the transfer of assets contributed by Abengoa prior to the consummation of our initial public offering through a series of transactions;

- references to "Atlantica" refer to Atlantica Yield plc and, where the context requires, its consolidated subsidiaries;

- references to "COD" refer to the commercial operation date of the applicable facility;

- references to "cash available for distribution" refer to the cash distributions received by the Company from its subsidiaries minus cash expenses of the Company, including debt service and general and administrative expenses;

- references to "DOE" refer to the U.S. Department of Energy;

- references to "EMEA" refer to Europe, Middle East and Africa;

- references to "EPC" refer to engineering, procurement and construction;

- references to "Exchange Act" refer to the U.S. Securities Exchange Act of 1934, as amended, or any successor statute, and the rules and regulations promulgated by the SEC thereunder;

- references to "FPA" refer to the U.S. Federal Power Act;

- references to "Federal Financing Bank" refer to a U.S. government corporation by that name;

- references to "Financial Support Agreement" refer to the Financial Support Agreement we entered into with Abengoa on June 13, 2014, as amended and restated on September 28, 2017, pursuant to which Abengoa agreed to maintain certain guarantees or letters of credit for a period of five years following our IPO;

- references to the "First Dropdown Assets" refer to (i) a solar power complex in Spain, Solacor 1/2, with a capacity of 100 MW; (ii) a solar power complex in Spain, PS10/20, with a capacity of 31 MW; and (iii) one on-shore wind farm in Uruguay, Cadonal, with a capacity of 50 MW, each as further described in "Item 4.B—Business Overview—Our Operations—Renewable Energy;"

- references to the "Fourth Dropdown Asset" refer to (i) 74.99% of the shares and a 30-year usufruct of the economic and political rights of the remaining 25.01% of the shares of Solaben 1/6, a 100 MW solar power complex in Spain, (ii) ATN2, an 81-mile transmission line in Peru, and (iii) an additional 13% stake in Solacor 1/2, each as further described in "Item 4.B—Business Overview—Our Operations—Renewable Energy" and "—Our Operations—Electric Transmission;"

- references to "Further Adjusted EBITDA" have the meaning set forth in "Presentation of Financial Information—Non-GAAP Financial Measures;"

- references to "GW" refer to gigawatts;

- references to "gross capacity" or "gross MW" refers to the maximum, or rated, power generation capacity, in MW, of a facility or group of facilities, without adjusting for the facility's power parasitics' consumption, or by our percentage of ownership interest in such facility as of the date of this annual report;

- references to "IFRIC 12" refer to International Financial Reporting Interpretations Committee's Interpretation 12—Service Concessions Arrangements;

- references to "IFRS as issued by the IASB" refer to International Financial Reporting Standards as issued by the International Accounting Standards Board;

- reference to "IPO" refer to our initial public offering of ordinary shares in June 2014;

- references to "ITC" refer to investment tax credits;

- references to "M ft3" refer to million cubic feet;

- references to "MW" refer to megawatts;

- references to "MWh" refer to megawatt hours;

- references to "New Money 1 Tradable Notes" refer to asset-backed notes issued by Abengoa as part of its restructuring plan. The New Money 1 Tradable Notes are senior in status and are secured by a ring-fenced structure that consists of a pledge over the shares Abengoa owns in us and A3T, a cogeneration plant in Mexico;

- references to "Note Issuance Facility" refer to the senior secured note facility dated February 10, 2017, of €275 million (approximately $330 million), with U.S. Bank as facility agent and a group of funds managed by Westbourne Capital as purchasers of the notes issued thereunder;

- references to "O&M" refer to operations and maintenance services provided at our various facilities;

- references to "operation" refer to the status of projects that have reached COD (as defined above);

- references to "PPA" refer to the power purchase agreements through which our power generating assets have contracted to sell energy to various offtakers;

- references to "PTC" refer to production tax credits;

- references to "Revolving Credit Facility" refer to the amended and restated revolving credit and guaranty agreement, dated June 26, 2015 entered into by us, as the borrower, the guarantors from time to time party thereto, HSBC Bank plc, as administrative agent, HSBC Corporate Trust Company (UK) Limited, as collateral agent, Bank of America, N.A., as global coordinator and documentation agent for the Tranche B, Banco Santander, S.A., Bank of America, N.A., Citigroup Global Markets Limited, HSBC Bank plc and RBC Capital Markets, as joint lead arrangers and joint bookrunners for a Tranche A facility, and together with Barclays Bank plc as joint lead arranger and joint bookrunner and UBS AG, London Branch as joint bookrunner for the Tranche B. The Tranche B was prepaid and cancelled in March 2017. See "Item 5.B—Liquidity and Capital Resources—Financing Arrangements—Revolving Credit Facility;"

- references to "ROFO" refer to a right of first offer;

- references to "ROFO Agreements" refer to the AAGES ROFO Agreement, Algonquin ROFO Agreement and Abengoa ROFO Agreement;

- references to "RPS" refer to renewable portfolio standards adopted by 29 U.S. states and the District of Columbia that require a regulated retail electric utility to procure a specific percentage of its total electricity delivered to retail customers in the respective state from eligible renewable generation resources, such as solar or wind generation facilities, by a specific date;

- references to the "Second Dropdown Assets" refer to (i) a 25.5% and a 34.2% stake, respectively, in the legal entities holding two water desalination plants in Algeria, Honaine and Skikda, with an aggregate capacity of 10.5 M ft3 per day and (ii) a 29.6% stake in the legal entity holding solar power assets in Spain, Helioenergy 1/2, with a capacity of 100 MW, each as further described in "Item 4.B—Business Overview—Our Operations—Water" and "Item 4.B—Business Overview—Our Operations—Renewable Energy;"

- references to "Share Sale" refer to the sale by Abengoa to Algonquin of 25% of our ordinary shares pursuant to an agreement for the sale that was entered into in November 2017. All conditions precedent have been satisfied and the parties have commenced the process for the transfer of our shares, which we expect to close in the upcoming days;

- references to the "Shareholders' Agreement" refer to the agreement by and among Algonquin Power & Utilities Corp., Abengoa-Algonquin Global Energy Solutions and Atlantica Yield plc, dated March 5, 2018 which will become effective upon completion of the Share Sale;

- references to "Third Dropdown Assets" refer to (i) Helios 1/2, a 100 MW solar power complex in Spain; (ii) Solnova 1/3/4, a 150 MW solar power complex in Spain; (iii) the remaining 70.4% stake in Helioenergy 1/2, a 100 MW solar power complex in Spain; and (iv) a 51.0% stake in Kaxu, a 100 MW solar power plant in South Africa, each as further described in "Item 4.B—Business Overview—Our Operations—Renewable Energy;"

- references to "U.K." refer to the United Kingdom;

- reference to "U.S." or "United States" refer to the United States of America;

- references to "UTE" refer to Administracion Nacional de Usinas y Transmisiones Electricas, the Republic of Uruguay's state-owned electricity company; and

- references to "we," "us," "our," "Atlantica" and the "Company" refer to Atlantica Yield plc and its subsidiaries, unless the context otherwise requires.

PRESENTATION OF FINANCIAL INFORMATION

The selected financial information as of December 31, 2017 and 2016 and for the years ended December 31, 2017, 2016 and 2015 is derived from, and qualified in its entirety by reference to, our Annual Consolidated Financial Statements, which are included elsewhere in this annual report and prepared in accordance with IFRS as issued by the IASB. The selected financial information as of December 31, 2015, 2014 and 2013 and for the years ended December 31, 2014 and 2013 is derived from, and qualified in its entirety by reference to, the annual consolidated financial statements as of December 31, 2016 and 2015 and for the years ended December 31, 2016, 2015 and 2014, which are included in the annual report on Form 20-F filed with the SEC on February 28, 2017, and prepared in accordance with IFRS as issued by the IASB.

On June 18, 2014, we closed our IPO. Prior to the consummation of our IPO, Abengoa contributed, through a series of transactions, which we refer to collectively as the “Asset Transfer,” certain contracted and concessional assets and liabilities described in this annual report, certain holding companies and a preferred equity investment in ACBH. For all periods prior to our IPO, the financial information herein represents the combination of the assets that we acquired and was prepared using Abengoa’s historical basis in the assets and liabilities and the term “Atlantica Yield” (or “Abengoa Yield,” our former name) represents the accounting predecessor, or the combination of the acquired businesses. For all periods subsequent to our IPO, the financial information herein represents our and our subsidiaries’ annual consolidated financial results.

Certain numerical figures set out in this annual report, including financial data presented in millions or thousands and percentages describing market shares, have been subject to rounding adjustments, and, as a result, the totals of the data in this annual report may vary slightly from the actual arithmetic totals of such information. Percentages and amounts reflecting changes over time periods relating to financial and other data set forth in “Item 5—Operating and Financial Review and Prospects” are calculated using the numerical data in our Annual Consolidated Financial Statements or the tabular presentation of other data (subject to rounding) contained in this annual report, as applicable, and not using the numerical data in the narrative description thereof.

Non-GAAP Financial Measures

This annual report contains non-GAAP financial measures including Further Adjusted EBITDA.

Further Adjusted EBITDA is calculated as profit/(loss) for the year attributable to the parent company, after adding back loss/(profit) attributable to non-controlling interest from continued operations, income tax, share of profit/(loss) of associates carried under the equity method, finance expense net, depreciation, amortization and impairment charges of entities included in the Annual Consolidated Financial Statements, and dividends received from our preferred equity investment in ACBH. Further Adjusted EBITDA for 2014, includes preferred dividends received from ACBH for the first time during the third and fourth quarters of 2014. Further Adjusted EBITDA for 2016 and for first quarter of 2017 includes compensation received from Abengoa in lieu of ACBH dividends.

Our management believes Further Adjusted EBITDA is useful to investors and other users of our financial statements in evaluating our operating performance because it provides them with an additional tool to compare business performance across companies and across periods. This measure is widely used by investors to measure a company’s operating performance without regard to items such as interest expense, taxes, depreciation and amortization, which can vary substantially from company to company depending upon accounting methods and book value of assets, capital structure and the method by which assets were acquired. This measure is widely used by other companies in the same industry,

Our management uses Further Adjusted EBITDA as a measure of operating performance to assist in comparing performance from period to period on a consistent basis and to readily view operating trends, as a measure for planning and forecasting overall expectations and for evaluating actual results against such expectations, and in communications with our board of directors, shareholders, creditors, analysts and investors concerning our financial performance.

We present non-GAAP financial measures because we believe that they and other similar measures are widely used by certain investors, securities analysts and other interested parties as supplemental measures of performance and liquidity. The non-GAAP financial measures may not be comparable to other similarly titled measures of other companies and have limitations as analytical tools and should not be considered in isolation or as a substitute for analysis of our operating results as reported under IFRS as issued by the IASB. Non-GAAP financial measures and ratios are not measurements of our performance or liquidity under IFRS as issued by the IASB and should not be considered as alternatives to operating profit or profit for the year or any other performance measures derived in accordance with IFRS as issued by the IASB or any other generally accepted accounting principles or as alternatives to cash flow from operating, investing or financing activities.

Some of the limitations of these non-GAAP measures are:

- they do not reflect our cash expenditures or future requirements for capital expenditures or contractual commitments;
- they do not reflect changes in, or cash requirements for, our working capital needs;
- they may not reflect the significant interest expense, or the cash requirements necessary, to service interest or principal payments, on our debts;
- although depreciation and amortization are non-cash charges, the assets being depreciated and amortized will often need to be replaced in the future and Further Adjusted EBITDA does not reflect any cash requirements that would be required for such replacements;
- some of the exceptional items that we eliminate in calculating Further Adjusted EBITDA reflect cash payments that were made, or will be made in the future; and
- the fact that other companies in our industry may calculate Further Adjusted EBITDA differently than we do, which limits their usefulness as comparative measures.

PRESENTATION OF INDUSTRY AND MARKET DATA

In this annual report, we rely on, and refer to, information regarding our business and the markets in which we operate and compete. The market data and certain economic and industry data and forecasts used in this annual report were obtained from internal surveys, market research, governmental and other publicly available information, independent industry publications and reports prepared by industry consultants. We believe that these industry publications, surveys and forecasts are reliable, but we have not independently verified them, and there can be no assurance as to the accuracy or completeness of the included information.

Certain market information and other statements presented herein regarding our position relative to our competitors are not based on published statistical data or information obtained from independent third parties but reflect our best estimates. We have based these estimates upon information obtained from our customers, trade and business organizations and associations and other contacts in the industries in which we operate.

Elsewhere in this annual report, statements regarding our contracted concessions activities, our position in the industries and geographies in which we operate are based solely on our experience, our internal studies and estimates and our own investigation of market conditions.

All of the information set forth in this annual report relating to the operations, financial results or market share of our competitors has been obtained from information made available to the public in such companies' publicly available reports and independent research, as well as from our experience, internal studies, estimates and investigation of market conditions. We have not funded, nor are we affiliated with, any of the sources cited in this annual report. We have not independently verified the information and cannot guarantee its accuracy.

All third-party information, as outlined above, has to our knowledge been accurately reproduced and, as far as we are aware and are able to ascertain, no facts have been omitted which would render the reproduced information inaccurate or misleading, but there can be no assurance as to the accuracy or completeness of the included information.

PART I

ITEM 1. IDENTITY OF DIRECTORS, SENIOR MANAGEMENT AND ADVISERS

Not applicable.

ITEM 2. OFFER STATISTICS AND EXPECTED TIMETABLE

Not applicable.

ITEM 3. KEY INFORMATION

A. Selected Financial Data

The tables below present selected consolidated financial and business level information for Atlantica Yield as of and for each of the years ended December 31, 2017, 2016, 2015, 2014 and 2013.

The selected financial information as of December 31, 2017 and 2016 and for the years ended December 31, 2017, 2016 and 2015 is derived from, and qualified in its entirety by reference to, our Annual Consolidated Financial Statements, which are included elsewhere in this annual report and prepared in accordance with IFRS as issued by the IASB. The selected financial information as of December 31, 2015, 2014 and 2013 and for the years ended December 31, 2014 and 2013, is derived from, and qualified in its entirety by reference to, the annual consolidated financial statements as of December 31, 2016 and 2015 and for the years ended December 31, 2016, 2015 and 2014, which are included in the annual report on Form 20-F with the SEC on February 28, 2017, and prepared in accordance with IFRS as issued by the IASB.

On June 18, 2014, we closed our IPO. Prior to the consummation of our IPO, Abengoa contributed, through a series of transactions, which we refer to collectively as the "Asset Transfer," certain contracted and concessional assets and liabilities described in this annual report, certain holding companies and a preferred equity investment in ACBH. For all periods prior to our IPO, the financial information herein represents the combination of the assets or the combination of businesses that we acquired and was prepared using Abengoa's historical basis in the assets and liabilities and the term "Atlantica Yield" (or "Abengoa Yield," our former name) represents the accounting predecessor, or the combination of the acquired businesses. For all periods subsequent to our IPO, the financial information herein represents our and our subsidiaries' annual consolidated financial results.

The selected financial information as of and for the years ended December 31, 2017, 2016, 2015, 2014 and 2013 is not intended to be an indicator of our financial condition or results of operations in the future. You should review such selected financial information together with our Annual Consolidated Financial Statements and notes thereto, included elsewhere in this annual report.

The following tables should be read in conjunction with "Item 5—Operating and Financial Review and Prospects" and our Annual Consolidated Financial Statements and related notes included elsewhere in this annual report.

Consolidated income statements for the years ended December 31, 2017, 2016, 2015, 2014 and 2013

	Year ended December 31,				
	2017	2016	2015	2014	2013
	($ in millions)				
Revenue	1,008.4	971.8	790.9	362.7	210.9
Other operating income	80.8	65.5	68.8	79.9	379.6
Raw materials and consumables used	(17.0)	(26.9)	(23.2)	(9.4)	(6.2)
Employee benefit expense	(18.7)	(14.8)	(5.8)	(1.7)	(2.4)
Depreciation, amortization and impairment charges	(311.0)	(332.9)	(261.3)	(125.5)	(46.9)
Other operating expenses	(284.5)	(260.3)	(224.9)	(132.7)	(423.4)
Operating profit/(loss)	**458.0**	**402.4**	**344.5**	**173.3**	**111.6**
Financial income	1.0	3.3	3.5	4.9	1.2
Financial expense	(463.7)	(408.0)	(333.9)	(210.3)	(123.8)
Net exchange differences	(4.1)	(9.6)	3.9	2.1	(0.9)
Other financial income/(expense), net	18.4	8.5	(200.2)	5.9	(1.7)
Financial expense, net	**(448.4)**	**(405.8)**	**(526.7)**	**(197.4)**	**(125.2)**
Share of profit/(loss) of associates carried under the equity method	5.3	6.7	7.8	(0.8)	—
Profit/(loss) before income tax	**14.9**	**3.3**	**(174.4)**	**(24.9)**	**(13.6)**
Income tax benefit/(expense)	(119.8)	(1.7)	(23.8)	(4.4)	11.8
Profit/(loss) for the year	**(104.9)**	**1.6**	**(198.2)**	**(29.3)**	**(1.8)**
Profit/(loss) attributable to non-controlling interest	(6.9)	(6.5)	(10.8)	(2.3)	(1.6)
Loss for the year attributable to the parent company	**(111.8)**	**(4.9)**	**(209.0)**	**(31.6)**	**(3.4)**
Less Predecessor Loss prior to Initial Public Offering on June 12, 2014	—	—	—	(28.2)	—
Net profit/(loss) attributable to the parent company subsequent to Initial Public Offering	—	—	—	(3.4)	—
Weighted average number of ordinary shares outstanding (millions)	100.2	100.2	92.8	80.0	—
Basic earnings per share attributable to the parent company (U.S. dollar per share) (1)	(1.12)	(0.05)	(2.25)	(0.04)	—
Dividend paid per share(2)	1.05	0.4530	1.4292	0.2962	—

Notes:—

(1) Earnings per share has been calculated for the period subsequent to our IPO, considering net profit/(loss) attributable to equity holders of Atlantica Yield generated after our IPO divided by the number of shares outstanding. Basic earnings per share equals diluted earnings per share for the periods presented.

(2) **2017:** On February 27, 2017, the board of directors declared a dividend of $0.25 per share corresponding to the fourth quarter of 2016, which was paid on March 15, 2017. From that amount, we retained $10.4 million of the dividend attributable to Abengoa. On May 12, 2017, the board of directors declared a dividend of $0.25 per share corresponding to the first quarter of 2017 which was paid on June 15, 2017. On July 28, 2017, the board of directors declared a dividend of $0.26 per share corresponding to the second quarter of 2017 which was paid on August 31, 2017. On November 10, 2017, the board of directors declared a dividend of $0.29 per share corresponding to the third quarter of 2017 which was paid on December 15, 2017.

2016: In February 2016, taking into consideration the uncertainties resulting from the situation of Abengoa, the board of directors decided to postpone the decision whether to declare a dividend in respect of the fourth quarter of 2015 until the second quarter of 2016. In May 2016, considering the uncertainties in Abengoa's situation, our board of directors decided not to declare a dividend in respect of the fourth quarter of 2015 and to postpone the decision on whether to declare a dividend in respect of the first quarter 2016 until we had obtained greater clarity on cross default and change of ownership issues. On August 3, 2016, based on waivers or forbearances obtained to that date, our board of directors decided to declare a dividend of $0.145 per share for the first quarter of 2016 and a dividend of $0.145 per share for the second quarter of 2016. The dividend was paid on September 15, 2016, to shareholders of record August 31, 2016. From that amount, we retained $12.3 million of the dividend attributable to Abengoa. On November 11, 2016, our board of directors, based on waivers or forbearances obtained to that date, decided to declare a dividend of $0.163 per share, paid on December 15, 2016, to shareholders of record on November 30, 2016, and from that amount we retained $6.7 million of the dividend attributable to Abengoa in accordance with the provisions of the parent support agreement and an agreement reached with Abengoa in relation to the ACBH preferred equity investment.

2015: On March 16, 2015 we paid a dividend of $0.2592 per share to shareholders of record February 28, 2015. On June 15, 2015 we paid a dividend of $0.34 per share to shareholders of record May 29, 2015. On September 15, 2015 we paid a dividend of $0.40 per share to shareholders of record May 29, 2015. On December 16, 2015, we paid a dividend of $0.43 per share to shareholders of record as of November 30, 2015, corresponding to the third quarter of 2015, and from that amount we retained $9 million of the dividend attributable to Abengoa in accordance with the provisions of the parent support agreement and an agreement reached with Abengoa in relation to the ACBH preferred equity investment. See "Item 4.B—Business Overview—Electric Transmission—Exchangeable Preferred Equity Investment in Abengoa Concessões Brasil Holding."

2014: On December 15, 2014 we paid a dividend of $0.2962 per share that consisted of $0.2592 per share announced by our board of directors on November 14, 2014 and $0.0370 per share of the pro-rata for the days from IPO on June 18, 2014 to June 30, 2014.

Consolidated statements of financial position as of December 31, 2017, 2016, 2015, 2014 and 2013

	As of December 31,				
	2017	**2016**	**2015**	**2014**	**2013**
			($ in millions)		
Non-Current assets:					
Contracted concessional assets	9,084.2	8,924.2	9,300.9	6,725.2	4,418.1
Investments carried under the equity method	55.8	55.0	56.2	5.7	387.3
Financial investments	45.3	69.8	93.8	373.6	28.9
Deferred tax assets	165.1	202.9	191.3	124.2	52.8
Total non-current assets	**9,350.4**	**9,251.9**	**9,642.2**	**7,228.7**	**4,887.1**
Current assets:					
Inventories	17.9	15.5	14.9	22.0	5.2
Clients and other receivables	244.4	207.6	197.3	129.7	97.6
Financial investments	210.1	228.0	221.4	229.4	266.4
Cash and cash equivalents	669.4	594.8	514.7	354.2	357.7
Total current assets	**1,141.9**	**1,045.9**	**948.3**	**735.3**	**726.9**
Total assets	**10,492.3**	**10,297.8**	**10,590.5**	**7,964.0**	**5,614.0**
Total equity	**1,895.4**	**1,959.1**	**2,023.5**	**1,839.6**	**1,287.2**
Non-current liabilities:					
Long-term corporate debt	574.2	376.3	661.3	376.2	—
Long-term project debt	5,228.9	4,629.2	3,574.5	3,491.9	2,842.3
Other liabilities	2,292.9	2,158.1	2,238.4	1,675.3	1,209.5
Total non-current liabilities	**8,096.5**	**7,163.6**	**6.474.2**	**5,543.4**	**4,051.8**
Current liabilities:					
Short-term corporate debt	68.9	291.9	3.2	2.3	—
Short-term project debt	246.3	701.3	1,896.1	331.2	52.4
Other liabilities	187.0	181.9	193.5	247.5	222.6
Total current liabilities	**500.4**	**1,175.1**	**2,092.8**	**581.0**	**275.0**
Equity and total liabilities	**10,492.3**	**10,297.8**	**10,590.5**	**7,964.0**	**5,614.0**

Consolidated cash flow statements for the years ended December 31, 2017, 2016, 2015, 2014 and 2013

	Year ended December 31,				
	2017	2016	2015	2014	2013
			($ in millions)		
Gross cash flows from operating activities					
Profit/(loss) for the year	(104.9)	1.6	(198.2)	(29.3)	(1.8)
Adjustments to reconcile after-tax profit to net cash generated by operating activities	848.8	664.8	734.9	290.6	92.4
Profit for the year adjusted by non-monetary items	**743.9**	**666.4**	**536.7**	**261.3**	**90.6**
Net interest / taxes paid	(349.5)	(334.0)	(310.2)	(149.7)	(62.4)
Variations in working capital	(8.8)	2.0	73.1	(68.0)	9.2
Total net cash flow provided by/(used in) operating activities	**385.6**	**334.4**	**299.6**	**43.6**	**37.4**
Net cash flows from investing activities					
Investments in entities under the equity method	3.0	5.0	4.4	(44.5)	(240.6)
Investments in contracted concessional assets[1]	30.1	(6.0)	(106.0)	(57.0)	(401.7)
Other non-current assets/liabilities	8.2	(3.6)	5.7	(21.3)	(52.3)
Acquisitions / sales of subsidiaries and other financial instruments	30.1	(21.7)	(834.0)	(222.4)	—
Total net cash flows provided by/(used in) investing activities	**71.4**	**(26.3)**	**(929.9)**	**(345.2)**	**(694.6)**
Net cash flows provided by/(used in) financing activities	**(416.3)**	**(226.1)**	**810.9**	**304.4**	**914.9**
Net increase/(decrease) in cash and cash equivalents	**40.7**	**82.0**	**180.6**	**2.9**	**257.7**
Cash, cash equivalents and bank overdrafts at beginning of the year	**594.8**	**514.7**	**354.2**	**357.7**	**97.5**
Translation differences cash or cash equivalents	33.9	(1.9)	(20.1)	(6.4)	2.5
Cash and cash equivalents at the end of the year	**669.4**	**594.8**	**514.7**	**354.2**	**357.7**

Note:—

(1) Includes proceeds for $42.5 million and investments for $12.4 million. See note 6 of the Annual Consolidated Financial Statements.

Geography and business sector data

Revenue by geography

	Year ended December 31,				
	2017	**2016**	**2015**	**2014**	**2013**
			($ in millions)		
North America	332.7	337.0	328.1	195.5	114.0
South America	120.8	118.8	112.5	83.6	25.4
EMEA	554.9	516.0	350.3	83.6	71.5
Total revenue	**1,008.4**	**971.8**	**790.9**	**362.7**	**210.9**

Revenue by business sector

	Year ended December 31,				
	2017	**2016**	**2015**	**2014**	**2013**
			($ in millions)		
Renewable energy	767.2	724.3	543.0	170.7	82.7
Efficient natural gas power	119.8	128.1	138.7	118.8	102.8
Electric transmission	95.1	95.1	86.4	73.2	25.4
Water	26.3	24.3	22.8	—	—
Total revenue	**1,008.4**	**971.8**	**790.9**	**362.7**	**210.9**

Non-GAAP Financial Data

Further Adjusted EBITDA by geography

	Year ended December 31,				
	2017	**2016**	**2015**	**2014**	**2013**
			($ in millions)		
North America	282.3	284.7	279.6	175.4	96.7
South America	108.8	124.6	110.9	77.2	19.0
EMEA	388.2	354.0	233.7	55.4	42.8
Further Adjusted EBITDA(1)	**779.3**	**763.3**	**624.2**	**308.0**	**158.5**

Further Adjusted EBITDA by business sector

	Year ended December 31,				
	2017	**2016**	**2015**	**2014**	**2013**
			($ in millions)		
Renewable energy	569.2	538.4	414.0	137.8	55.8
Efficient natural gas power	106.1	106.5	107.7	101.9	83.3
Electric transmission	87.7	104.8	89.0	68.3	19.4
Water	16.3	13.6	13.5	—	—
Further Adjusted EBITDA(1)	**779.3**	**763.3**	**624.2**	**308.0**	**158.5**

Note:—

(1) Further Adjusted EBITDA is calculated as profit/(loss) for the year attributable to the parent company, after adding back loss/(profit) attributable to non-controlling interest from continued operations, income tax, share of profit/(loss) of associates carried under the equity method, finance expense net, depreciation, amortization and impairment charges of entities included in the Annual Consolidated Financial Statements, and dividends received from our preferred equity investment in ACBH. Further Adjusted EBITDA for 2014, includes preferred dividends by ACBH for the first time during the third and fourth quarters of 2014. Further Adjusted EBITDA for 2016 and the first quarter of 2017 includes compensation received from Abengoa in lieu of ACBH dividends. Further Adjusted EBITDA is not a measure of performance under IFRS as issued by the IASB and you should not consider Further Adjusted EBITDA as an alternative to operating income or profits or as a measure of our operating performance, cash flows from operating, investing and financing activities or as a measure of our ability to meet our cash needs or any other measures of performance under generally accepted accounting principles. We believe that Further Adjusted EBITDA is a useful indicator of our ability to incur and service our indebtedness and can assist securities analysts, investors and other parties to evaluate us. Further Adjusted EBITDA and similar measures are used by different companies for different purposes and are often calculated in ways that reflect the circumstances of those companies. Further Adjusted EBITDA may not be indicative of our historical operating results, nor is it meant to be predictive of potential future results. See "Presentation of Financial Information—Non-GAAP Financial Measures."

The following table sets forth a reconciliation of Further Adjusted EBITDA to our profit/(loss) for the year from continuing operations:

Reconciliation of profit/(loss) for the year to Further Adjusted EBITDA

	Year ended December 31,				
	2017	**2016**	**2015**	**2014**	**2013**
			($ in millions)		
Profit/(loss) for the year attributable to the parent company	**(111.8)**	**(4.9)**	**(209.0)**	**(31.6)**	**(3.4)**
Profit/(loss) attributable to non-controlling interest from continued operations	6.9	6.5	10.8	2.3	1.6
Income tax	119.8	1.7	23.8	4.4	(11.8)
Share of loss/(profit) of associates carried under the equity method	(5.3)	(6.7)	(7.8)	0.8	—
Financial expenses, net	448.4	405.8	526.7	197.4	125.2
Operating profit/(loss)	**458.0**	**402.4**	**344.5**	**173.3**	**111.6**
Depreciation, amortization and impairment charges	311.0	332.9	261.3	125.5	46.9
Dividend from preferred equity investment	10.3	28.0	18.4	9.2	—
Further Adjusted EBITDA	**779.3**	**763.3**	**624.2**	**308.0**	**158.5**

The following table sets forth a reconciliation of Further Adjusted EBITDA to our net cash generated by or used in operating activities:

Reconciliation of Further Adjusted EBITDA to net cash generated by operating activities

	Year ended December 31,				
	2017	**2016**	**2015**	**2014**	**2013**
			($ in millions)		
Net cash generated by operating activities	**385.6**	**334.4**	**299.6**	**43.6**	**37.4**
Interests (paid)/received	344.7	332.1	310.2	149.3	62.3
Income tax (paid)/received	4.8	2.0	(0.5)	0.4	0.1
Variations in working capital	8.8	(2.0)	(73.1)	68.0	(9.2)
Non-monetary adjustments, other cash finance costs and other	35.4	96.8	88.0	46.7	67.9
Further Adjusted EBITDA	**779.3**	**763.3**	**624.2**	**308.0**	**158.5**

B. Capitalization and Indebtedness

Not applicable.

C. Reasons for the Offer and Use of Proceeds

Not applicable.

D. Risk Factors

Investing in our securities involves a high degree of risk. You should carefully consider the risks and uncertainties described below, together with the other information contained in this annual report, including our Annual Consolidated Financial Statements and related notes, included elsewhere in this annual report, before making any investment decision. The risks described below may not be the only risks we face. We have described only those risks that we currently consider to be material and there may be additional risks that we do not currently consider to be material or of which we are not currently aware. Any of the following risks and uncertainties could have a material adverse effect on our business, prospects, results of operations and financial condition. The market price of our securities could decline due to any of these risks and uncertainties, and you could lose all or part of your investment.

Risks Related to Our Business and the Markets in Which We Operate

Difficult conditions in the global economy and in the global capital markets have caused, and may continue to cause, a sharp reduction in worldwide demand for our products and services and negatively affect our access to the levels of financing necessary for the successful refinancing of our project level and corporate level indebtedness

Our results of operations have been, and continue to be, materially affected by conditions in the global economy and in the global capital markets. Concerns over inflation, volatile oil and gas prices, geopolitical issues, the availability and cost of credit, sovereign debt and the instability of the euro have contributed to increased volatility and diminished expectations for the economy and global capital markets going forward. These factors have in the past precipitated economic slowdowns and led to a recent recession and weak economic growth. Adverse events and continuing disruptions in the global economy and in the global capital markets may have a material adverse effect on our business, financial condition, results of operations and cash flows. Moreover, even in the absence of a market downturn, we are exposed to substantial risk of loss due to market volatility with certain factors, including volatile oil prices, interest rates, consumer spending, business investment, government spending, inflation affecting the business and economic environment that could affect the economic and financial situation of our concession contracts counterparties and, ultimately, the profitability and growth of our business.

Generalized or localized downturns or inflationary or deflationary pressures in our key geographical areas could also have a material adverse effect on the performance of our business. A significant portion of our business activity is concentrated in the United States, Mexico, Peru and Spain. Consequently, we are significantly affected by the general economic conditions in these countries. Spain, for instance, has recently experienced negative economic conditions, including high unemployment and significant government debt, increased lately by the uncertainty of the Catalonia political situation, which we believe could adversely affect our operations in the future. The effects on the European and global economy of the exit of the United Kingdom from the European Union or of any other member states from the Eurozone, the dissolution of the euro and the possible redenomination of our financial instruments or other contractual obligations from euro into a different currency, or the perception that any of these events are imminent, are inherently difficult to predict and could give rise to operational disruptions or other risks of contagion to our business and have a material, adverse effect on our business, financial condition and results of operation. In addition, to the extent uncertainty regarding the European economic recovery continues to negatively affect government or regional budgets, our business, results of operations and cash flows could be materially adversely affected. Various European political parties who question the recent austerity policies implemented in certain European countries have added political instability to the region. Additionally, political changes in key geographies, including the United States, could affect our business in the United States or in other countries including, for example, Mexico.

The global capital and credit markets have experienced in the past and may continue to experience periods of extreme volatility and disruption. Continued disruptions, uncertainty or volatility in the global capital and credit markets may limit our access to additional capital required to operate or grow our business, including our access to new debt and equity capital to make further acquisitions or access to project debt, which we may use to fund or refinance many of our projects and corporate level debt, even in cases where such capital has already been committed. Such market conditions may limit our ability to replace, in a timely manner, maturing liabilities and access the capital necessary to grow our business, or replace financing previously committed for a project that ceases to be available to it. As a result, we may be forced to delay raising capital, issue shorter-term securities than we prefer, or bear a higher cost of capital which could decrease our profitability and significantly reduce our financial flexibility or even require us to modify our dividend policy. In the event that we are required to replace previously committed financing to certain projects that subsequently becomes unavailable, we may have to postpone or cancel planned acquisitions or capital expenditures.

Government regulations providing incentives and subsidies for renewable energy could change at any time, including pursuant to the proposed environmental and tax policies of the current administration in the United States, and such changes may negatively impact our current business and our growth strategy

Our strategy to grow our business through the acquisition of renewable energy projects partly depends on current government policies that promote and support renewable energy and enhance the economic viability of owning solar and wind energy projects. Renewable energy projects currently benefit from various U.S. federal, state and local governmental incentives, such as ITCs, PTCs, loan guarantees, RPS programs, modified accelerated cost-recovery system of depreciation, or MACRS, for depreciation and new expensing rules under the "Tax Cuts and Jobs Act" (the "TCJA") along with other incentives. These policies have had a significant impact on the development of renewable energy and they could change at any time, especially in the event that the current administration was to embark on further significant changes in federal energy policy. Additionally, many of these government incentives, including the ITCs and the PTCs, are subject to phase-out and/or expiration. These incentives make the development of renewable energy projects more competitive by providing tax credits, accelerated depreciation and expensing for a portion of the development costs, decreasing the costs associated with developing such projects or creating demand for renewable energy assets through RPS programs. A loss or reduction in such incentives or the value of such incentives or a reduction in the capacity of potential investors to benefit from such incentives could decrease the attractiveness of solar or renewable energy projects to project developers, and the attractiveness of solar energy systems to utilities, retailers and customers, which could reduce our acquisition opportunities. Such a loss or reduction could also reduce our willingness to pursue renewable energy projects due to higher operating costs or lower revenues from offtake agreements.

The current administration's environmental and tax policies may create regulatory uncertainty in the clean energy sector and may lead to a reduction or removal of various clean energy programs and initiatives designed to curtail climate change. Such a reduction or removal of incentives may diminish the market for future renewable energy offtake agreements and reduce the ability for renewable developers to compete for future energy offtake agreements, which may reduce incentives for project developers, including AAGES and Abengoa, to develop such projects. To the extent that these policies are changed in a manner that reduces the incentives or the value of such incentives or reduces the capacity of potential investors to benefit from such incentives that benefit our projects, they could generate reduced revenues and reduced economic returns, result in increased financing costs and difficulty obtaining financing.

The TCJA reduced the U.S. corporate tax rates and imposed significant additional limitations on the deductibility of interest. The reduction in the corporate tax rate could diminish the benefit of tax incentives for potential investors and reduce the value of accelerated depreciation deductions and expensing certain capital expenditures. The current administration has also made public statements regarding overturning or modifying policies of, or regulations enacted by, the prior administration that placed limitations on coal and gas electric generation, mining and/or exploration. Any effort to overturn federal and state laws, regulations or policies that are supportive of existing or new solar energy generation or that remove costs or other limitations on other types of generation that compete with solar energy projects could materially and adversely affect our business. We currently have two financing arrangements with the Federal Financing Bank with a guarantee from the DOE and our projects benefitted from ITCs. Unilateral changes to these agreements could materially and adversely affect our business.

Additionally, some U.S. states with RPS targets have met, or in the near future will meet, their renewable energy targets. For example, California, which has among the most aggressive RPS laws in the United States, is poised to meet its current mandate of 33.0% renewable energy by 2020 with already-proposed new renewable energy projects, though significant additional investments will be required to meet the higher 50.0% renewable energy mandate that was adopted in 2015. If, as a result of achieving these targets, these and other U.S. states do not increase their targets in the near future, demand for additional renewable energy could decrease.

Potential acquisition of solar projects could be more challenging taking into account that the cost of solar panels has stabilized and could increase in the future, including as a result of increases in the cost of solar panels or tariffs on imported solar panels imposed by the U.S. government

The U.S. government has imposed tariffs on solar cells manufactured in China which is a large producer of solar cells. These tariffs have increased the price of solar panels containing Chinese-manufactured solar cells. The purchase price of solar panels containing solar cells manufactured in China reflects these tariff penalties. While solar panels containing solar cells manufactured outside of China are not subject to these tariffs, the prices of these solar panels are, and may continue to be, more expensive than panels produced using Chinese solar cells, before giving effect to the tariff penalties.

In addition, the U.S. government is conducting trade investigations relating to solar modules manufactured in China (with cells from other countries) and cells manufactured in Taiwan. In early January 2015, the U.S. government announced its affirmative final determinations in both the countervailing duty and anti-dumping cases against China and in the anti-dumping case again Taiwan. The new preliminary tariffs do not apply to modules with Chinese solar cells. Those modules are still covered by the existing tariffs from the first 2012 trade case.

The declining cost of solar panels and the raw materials necessary to manufacture them has been a key driver in the pricing of solar energy systems and customer adoption of this form of renewable energy. With the stabilization or increase of solar panel and raw materials prices, our growth could slow. Although we do not purchase solar panels directly, higher cost solar panels could make future purchases of solar assets more difficult.

We are exposed to political, social and macroeconomic risks relating to the United Kingdom's exit from the European Union

On June 23, 2016, the United Kingdom voted in a national referendum to withdraw from the European Union, or the EU, and the UK government invoked article 50 of the Lisbon Treaty related to withdrawal on March 29, 2017. Under article 50, the Treaty on the European Union and the Treaty on the Functioning of the European Union cease to apply in the relevant state from the date of entry into force of a withdrawal agreement or, failing that, two years after the notification of intention to withdraw, although this period may be extended in certain circumstances. Regardless of the eventual timing or terms of the United Kingdom's exit from the EU, the result of the June referendum continues to create significant political, social and macroeconomic uncertainty.

There are a number of areas of uncertainty in connection with the future of the United Kingdom and its relationship with the EU and the negotiation of the United Kingdom's exit terms and related matters may take several years. Given this uncertainty and the range of possible outcomes, it is not currently possible to determine the impact that the United Kingdom's departure from the EU and/or any related matters may have on general economic conditions in the United Kingdom. The exit of the United Kingdom (or any other country) from the EU or prolonged periods of uncertainty relating to any of these possibilities could result in significant macroeconomic deterioration, including, but not limited to, further decreases in global stock exchange indices, increased foreign exchange volatility, decreased GDP in the European Union or other markets in which the Group operates, and further sovereign credit downgrades. In addition, there could be changes to tax regulation affecting the repatriation of dividends from other countries, which may negatively affect us. Additionally, the impact of potential changes to the United Kingdom's migration policy could adversely impact our employees of non-UK nationality currently working in the United Kingdom, all of which could have an adverse effect on our operations.

We have international operations and investments, including in emerging markets that could be subject to economic, social and political uncertainties

We operate our activities in a range of international locations, including North America (the United States and Mexico), South America (Peru, Chile and Uruguay), and EMEA (Spain, Algeria and South Africa), and we may expand our operations to certain countries within these core regions. Accordingly, we face a number of risks associated with operating and investing in different countries that may have a material adverse effect on our business, financial condition, results of operations and cash flows. These risks include, but are not limited to, adapting to the regulatory requirements of such countries, compliance with changes in laws and regulations applicable to foreign corporations, the uncertainty of judicial processes, and the absence, loss or non-renewal of favorable treaties, or similar agreements, with local authorities or political, social and economic instability, all of which can place disproportionate demands on our management, as well as significant demands on our operational and financial personnel and business. As a result, we can provide no assurance that our future international operations and investments will remain successful.

A significant portion of our current and our potential future operations and investments are conducted in various emerging countries worldwide. Our activities and investments in these countries involve a number of risks that are more prevalent than in developed markets, such as economic and governmental instability, the possibility of significant amendments to, or changes in, the application of governmental regulations, the nationalization and expropriation of private property, payment collection difficulties, social problems, substantial fluctuations in interest and exchange rates, changes in the tax framework or the unpredictability of enforcement of contractual provisions, currency control measures, limits on the repatriation of funds and other unfavorable interventions or restrictions imposed by public authorities. Our U.S. dollar-denominated contracts in Algeria, Mexico, Chile and Peru are payable in local currency at the exchange rate of the payment date and our contract for Kaxu in South Africa is denominated and payable in South African rand. In the event of a rapid devaluation or implementation of exchange or currency controls, we may not be able to exchange the local currency for the agreed dollar amount, which could affect our cash available for distribution. Governments in Latin America and Africa frequently intervene in the economies of their respective countries and occasionally make significant changes in policy and regulations. Governmental actions in certain Latin American and African countries to control inflation and other policies and regulations have often involved, among other measures, price controls, currency devaluations, capital or exchange controls and limits on imports.

Decreases in government budgets, reductions in government subsidies and adverse changes in law may adversely affect our business and growth plan

Poor economic conditions have affected, and continue to affect, government budgets and threaten the continuation of government subsidies such as regulated revenues, cash grants, U.S. federal income tax benefits and other similar subsidies that benefit our business, particularly with respect to renewable energy. Such conditions may also lead to adverse changes in laws. Policies supporting the development of renewable energy have had a significant effect on the growth of investments in renewable energy and they could change at any time. Government subsidies and incentives make the development of renewable projects more competitive by providing tax credits and accelerated depreciation for a portion of the development costs, decreasing the costs associated with developing such projects or creating demand for renewable energy assets through RPS programs. A loss or reduction in such incentives could decrease the attractiveness of renewable energy projects to project developers and the attractiveness of renewable energy to utilities, which could reduce our acquisition opportunities. Such a loss or reduction could also reduce our willingness to pursue renewable energy projects due to higher operating costs or lower revenues. The reduction or elimination of subsidies or incentives or adverse changes in law could have a material adverse effect on the profitability of our existing projects, and the lack of availability of new projects undertaken in reliance on the continuation of such subsidies could adversely affect our growth plan.

Pursuant to our cash dividend policy, we expect to distribute a high percentage of our cash available for distribution after cash interest payments through regular quarterly distributions and dividends, and our ability to grow and make acquisitions through cash on hand could be limited

Our dividend policy is to distribute a high percentage of our cash available for distribution, after corporate general and administrative expenses and cash interest payments and less reserves for the prudent conduct of our business, each quarter and to rely primarily upon external financing sources, including the issuance of debt and equity securities as well as borrowings under credit facilities to fund our acquisitions and potential growth capital expenditures. Our target payout ratio is 80% of the cash available for distribution we generate, on an annual basis. See "Item 8.A—Consolidated Statements and Other Financial Information—Dividend Policy." We may be precluded from pursuing otherwise attractive acquisitions if the projected short-term cash flow from the acquisition or investment is not adequate to service the capital raised to fund the acquisition or investment, after giving effect to our available cash reserves. See "Item 8.A—Consolidated Statements and Other Financial Information—Dividend Policy—Our Ability to Grow our Business and Dividend."

We intend to, whenever possible, make regular quarterly cash distributions to our shareholders in an amount representing 80% of the cash available for distribution generated on an annual basis, taking into account reserves for the prudent conduct of our business. As such, our growth may not be as fast as that of businesses that reinvest their available cash to expand ongoing operations. To the extent we issue additional equity securities in connection with any acquisitions or growth capital expenditures, the payment of dividends on these additional equity securities may increase the risk that we will be unable to maintain or increase our per share dividend. There are no limitations in our articles of association on our ability to issue equity securities, including securities ranking senior to our shares. The issuance of additional debt securities and/or the incurrence of additional bank borrowings or other debt by us or by intermediate subsidiaries or by our project-level subsidiaries to finance our growth strategy could result in increased interest expense and the imposition of additional or more restrictive covenants, which, in turn, may impact the cash distributions we receive from our subsidiaries.

Our board of directors may change our dividend policy at any point in time or modify the dividend for specific quarters following prevailing conditions.

We may not be able to identify and reach agreements with new partners similar to the AAGES and Abengoa ROFO Agreements

We intend to enter into an agreement or agreements with new partners that own or develop renewable energy, electric transmission or water assets in the geographies in which we operate. Any such new partner would be a source of assets in addition to AAGES and Abengoa. We cannot be certain that we will be successful in identifying or reaching an agreement with new partners. We also cannot be certain that any agreement with a new partner will have terms similar to the AAGES and Abengoa ROFO Agreements and such terms may be less favorable to us. Even if we do reach an agreement with a new partner, we cannot be certain that we will be able to acquire assets from any such partner in the future.

If we are unable to identify and reach an agreement on favorable terms with new partners with suitable assets, and unable to consummate future acquisitions from any such sponsor, it may limit our ability to execute our growth strategy and limit our ability to increase the amount of dividends paid to holders of our shares.

We may not be able to arrange the required or desired financing for accretive acquisitions

Our ability to effectively consummate future acquisitions will also depend on our ability to arrange the required or desired financing for acquisitions or to refinance existing corporate debt. We may not have access to the capital markets to issue new equity or debt securities or sufficient availability under our credit facilities or have access to project-level financing on commercially reasonable terms when acquisition opportunities arise. During the second half of 2015 and first half of 2016, our access to financing was curtailed by market conditions and other factors. These adverse market conditions could recur in 2018, thereby preventing us from accessing the capital markets in a manner that would permit us to make an accretive acquisition.

An inability to obtain the required or desired financing could significantly limit our ability to consummate future acquisitions and effectuate our growth strategy. If financing is available, utilization of our credit facilities, debt securities or project-level financing for all or a portion of the purchase price of an acquisition, as applicable, could significantly increase our interest expense, impose additional or more restrictive covenants, and reduce cash available for distribution. Similarly, the issuance of additional equity securities as consideration for acquisitions could cause significant shareholder dilution and reduce our per share cash available for distribution if the acquisitions are not sufficiently accretive. If we are unable to obtain financing necessary for accretive acquisitions, it will impede our ability to execute our growth strategy and limit our ability to increase the amount of dividends paid to holders of our shares.

The Share Sale may not be completed

We cannot assure you that the closing of the Share Sale announced between Abengoa and Algonquin will be completed in the first quarter of 2018, or at all. Although all conditions precedent for the Share Sale have been satisfied and the parties have commenced the process for the transfer of our shares, if the Share Sale does not take place, the AAGES and Algonquin ROFO Agreements will not become effective and we will not derive the benefits of having a new strategic partner.

We may not be able to identify or consummate future acquisitions on favorable terms, or at all

Our business strategy includes growth through the acquisition of additional revenue-generating operational assets. This strategy depends on our ability to successfully identify and evaluate acquisition opportunities and consummate acquisitions on favorable terms. However, the number of acquisition opportunities may be limited. We cannot be certain that AAGES, Algonquin or Abengoa will offer us assets under the ROFO Agreements that fit within our portfolio of assets or contribute to our growth strategy. The Atacama project in Chile is currently owned by APW-1, an investment vehicle initially created by Abengoa as a joint venture with EIG and currently fully owned by EIG, an investment fund; although the Atacama project is subject to our ROFO agreement with APW-1, we cannot be certain that APW-1 will wish to sell the Atacama project at an attractive price or at all. See “Item 4.B—Business Overview—Our Growth Strategy.”

Our ability to acquire future renewable energy projects depends on the viability of renewable energy projects generally. These projects currently are largely contingent on public policy mechanisms including, among others, ITCs, cash grants, loan guarantees, accelerated depreciation, expensing for certain capital expenditures, carbon trading plans, environmental tax credits and R&D incentives, as discussed in “Item 4.B—Business Overview—Regulation—Regulation in the United States—Federal Considerations for Renewable Energy Generation Facilities.” These mechanisms have been implemented at the U.S. federal and state levels and in certain other jurisdictions where our assets are located to support the development of renewable generation and other clean infrastructure technologies. The availability and continuation of public policy support mechanisms will drive a significant part of the economics and viability of our growth strategy and expansion into clean energy investments.

Our ability to consummate future acquisitions may also depend on our ability to obtain any required government or regulatory approvals for such acquisitions, including, but not limited to, the Federal Energy Regulatory Commission, or FERC, approval under Section 203 of the FPA in respect of acquisitions in the United States; or any other approvals in the countries in which we may purchase assets in the future. We may also be required to seek authorizations, waivers or notifications from debt and/or equity financing providers at the project or holding company level; local or regional agencies or bodies; and/or development agencies or institutions that may have a contractual right to authorize a proposed acquisition.

Additionally, acquisitions of companies and assets are subject to substantial risks, including the failure to identify material problems during due diligence (for which we may not be indemnified post-closing), the risk of over-paying for assets (or not making acquisitions on an accretive basis) and the ability to retain customers. Further, the integration and consolidation of acquisitions requires substantial human, financial and other resources and, ultimately, our acquisitions may divert management’s attention from our existing business concerns, disrupt our ongoing business or not be successfully integrated. There can be no assurances that any future acquisitions will perform as expected or that the returns from such acquisitions will support the financing utilized to acquire them or maintain them. As a result, the consummation of acquisitions may have a material adverse effect on our business, financial condition, results of operations and cash flows and ability to pay dividends to holders of our shares.

Furthermore, we will compete with other companies for acquisition opportunities from third parties, which may increase our cost of making acquisitions or cause us to refrain from making acquisitions from third parties. Some of our competitors for acquisitions are much larger than us, with substantially greater resources. These companies may be able to pay more for acquisitions due to cost of capital advantages, synergy potential or other drivers, and may be able to identify, evaluate, bid for and purchase a greater number of assets than our financial or human resources permit. If we are unable to identify and consummate future acquisitions, it will impede our ability to execute our growth strategy and limit our ability to increase the amount of dividends paid to holders of our shares.

Our ability to consummate future acquisitions also depends on the availability of financing. See "We may not be able to arrange the required or desired financing for accretive acquisitions" above.

Finally, demand for renewable energy may be affected by the cost of other energy sources, including nuclear, coal, natural gas and oil. For example, low natural gas prices have led, in some instances, to increased natural gas consumption in lieu of other energy sources. To the extent renewable energy becomes less cost-competitive cheaper alternatives or otherwise, demand for renewable energy could decrease. Slow growth or a long-term reduction in the energy demand could cause a reduction in the development of renewable energy programs projects. Decreases in the prices of electricity could affect our ability to acquire accretive assets, as renewable energy developers may not be able to compete with providers of other energy sources at such lower prices. Our inability to acquire accretive assets could have a material adverse effect on our ability to execute our growth strategy.

We rely on certain regulations, subsidies and tax incentives that may be changed or legally challenged

We rely, in a significant part, on environmental and other regulations of industrial and local government activities, including regulations mandating, among other things, reductions in carbon or other greenhouse gas emissions or use of energy from renewable sources. If the businesses to which such regulations relate were deregulated or if such regulations were materially changed or weakened, the profitability of our current and future projects could suffer, which could in turn have a material adverse effect on our business, financial condition and results of operations. In addition, uncertainty regarding possible changes to any such regulations has adversely affected in the past, and may adversely affect in the future, our ability to refinance a project or to satisfy other financing needs.

Subsidy regimes for renewable energy generation have been challenged in the past on constitutional and other grounds (including that such regimes constitute impermissible European Union state aid) in certain jurisdictions. In addition, certain loan-guarantee programs in the United States, including those which have enabled the DOE to provide loan guarantees to support our Solana and Mojave projects, have been challenged on grounds of failure by the appropriate authorities to comply with applicable U.S. federal administrative and energy law. If all or part of the subsidy and incentive regimes for renewable energy generation in any jurisdiction in which we operate were found to be unlawful and, therefore, reduced or discontinued, we may be unable to compete effectively with conventional and other renewable forms of energy.

The production from our renewable energy facilities is the subject of various tax relief measures or tax incentives in the jurisdictions in which they operate. These tax relief and tax incentive measures play an important role in the profitability of our projects. In the future, it is possible that some or all of these tax incentives will be suspended, curtailed, not renewed or revoked. The occurrence of any of the above could adversely affect the profitability of our current plants and our ability to refinance projects, which could in turn have a material adverse effect on our business, financial condition, results of operations and cash flows.

We are subject to extensive governmental regulation in a number of different jurisdictions, and our inability to comply with existing regulations or requirements or changes in applicable regulations or requirements may have a negative impact on our business, results of operations or financial condition.

We are subject to extensive regulation of our business in the United States, Mexico, Spain, Peru and South Africa and in each of the other countries in which we operate. Such laws and regulations require licenses, permits and other approvals to be obtained in connection with the operations of our activities. See "Item 4.B—Business Overview—Regulation." This regulatory framework imposes significant actual, day-to-day compliance burdens, costs and risks on us. In particular, the power plants and transmission lines that we own are subject to strict international, national, state and local regulations relating to their operation and expansion (including, among other things, leasing and use of land, and corresponding building permits, landscape conservation, noise regulation, environmental protection and environmental permits and electric transmission and distribution network congestion regulations). Non-compliance with such regulations could result in the revocation of permits, sanctions, fines or even criminal penalties. Compliance with regulatory requirements, which may in the future include increased exposure to capital markets regulations, may result in substantial costs to our operations that may not be recovered. In addition, we cannot predict the timing or form of any future regulatory or law enforcement initiatives. Changes in existing energy, environmental and administrative laws and regulations may materially and adversely affect our business, margins and investments. Our business may also be affected by additional taxes imposed on our activities, reduction of regulated tariffs and other cuts or measures.

Further, similar changes in laws and regulations could increase the size and number of claims and damages asserted against us or subject us to enforcement actions, fines and even criminal penalties. In addition, changes in laws and regulations may, in certain cases, have retroactive effect and may cause the result of operations to be lower than expected. In particular, our activities in the energy sector are subject to regulations applicable to the economic regime of generation of electricity from renewable sources and to subsidies or public support in the benefit of the production of energy from renewable energy sources, which vary by jurisdiction, and are subject to modifications that may be more restrictive or unfavorable to us.

Our business is subject to stringent environmental regulation

We are subject to significant environmental regulation, which, among other things, requires us to obtain and maintain regulatory licenses, permits and other approvals and comply with the requirements of such licenses, permits and other approvals and perform environmental impact studies on changes to projects. There can be no assurance that:

- public opposition will not result in delays, modifications to or cancellation of any project or license;
- laws or regulations will not change or be interpreted in a manner that increases our costs of compliance or materially or adversely affects our operations or plants; or
- governmental authorities will approve our environmental impact studies where required to implement proposed changes to operational projects.

We believe that we are currently in material compliance with all applicable regulations, including those governing the environment. While we employ robust policies with regard to environmental regulation compliance, there are occasions where regulations are breached. On occasions, we have been found not to be in compliance with certain environmental regulations and have incurred fines and penalties associated with such violations which, to date, have not been material in amount. We can give no assurance, however, that we will continue to be in compliance or avoid material fines, penalties, sanctions and expenses associated with compliance issues in the future. Violation of such regulations may give rise to significant liability, including fines, damages, fees and expenses, and site closures. Generally, relevant governmental authorities are empowered to clean up and remediate releases of environmental damage and to charge the costs of such remediation and clean-up to the owners or occupiers of the property, the persons responsible for the release and environmental damage, the producer of the contaminant and other parties, or to direct the responsible parties to take such action. These governmental authorities may also impose a tax or other liens on the responsible parties to secure the parties' reimbursement obligations.

Environmental regulation has changed rapidly in recent years, and it is possible that we will be subject to even more stringent environmental standards in the future. For example, our activities are likely to be covered by increasingly strict national and international standards relating to climate change and related costs and may be subject to potential risks associated with climate change, which may have a material adverse effect on our business, financial condition or results of operations. We cannot predict the amounts of any increased capital expenditures or any increases in operating costs or other expenses that we may incur to comply with applicable environmental, or other regulatory, requirements, or whether these costs can be passed on to our concession contract counterparties through price increases.

Increases in the cost of energy and gas could increase the operating costs in some of our assets

Some of our activities require some consumption of energy and gas, and we are vulnerable to material fluctuations in their prices. For example, our Spanish solar assets produced a small percentage of their electricity using natural gas in 2017. Although our energy and gas purchase contracts generally include indexing mechanisms, we cannot guarantee that these mechanisms will cover all of the additional costs generated by an increase in energy and gas prices, particularly for long-term contracts, and some of the contracts entered into by us do not include any indexing provisions. Significant increases in the cost of energy or gas, or shortages of the supply of energy and/or gas, could have an adverse effect on our business, financial condition, results of operations and cash flows.

Counterparties to our offtake agreements may not fulfill their obligations and, as our contracts expire, we may not be able to replace them with agreements on similar terms in light of increasing competition in the markets in which we operate

A significant portion of the electric power we generate, the transmission capacity we have, and our desalination capacity is sold under long-term offtake agreements with public utilities, industrial or commercial end-users or governmental entities, with a weighted average remaining duration of approximately 19 years as of December 31, 2017**.**

If, for any reason, including, but not limited to, a deterioration in their financial situation, any of the purchasers of power, transmission capacity or desalination capacity under these agreements are unable or unwilling to fulfill their related contractual obligations or if they refuse to accept delivery of power delivered thereunder or if they otherwise terminate such agreements prior to the expiration thereof, our assets, liabilities, business, financial condition, results of operations and cash flow could be materially and adversely affected. Furthermore, to the extent any of our power, transmission capacity or desalination capacity purchasers are, or are controlled by, governmental entities, our facilities may be subject to sovereign risk or legislative or other political action that may impair their contractual performance.

The power generation industry is characterized by intense competition and our electric generation assets encounter competition from utilities, industrial companies and other independent power producers, in particular with respect to uncontracted output. In recent years, there has been increasing competition among generators for offtake agreements and this has contributed to a reduction in electricity prices in certain markets characterized by excess supply above designated reserve margins. In light of these market conditions, we may not be able to replace an expiring or terminated agreement with an agreement on equivalent terms and conditions, including at prices that permit operation of the related facility on a profitable basis. In addition, we believe many of our competitors have well-established relationships with our current and potential suppliers, lenders and customers and have extensive knowledge of our target markets. As a result, these competitors may be able to respond more quickly to evolving industry standards and changing customer requirements than we will be able to. Adoption of technology more advanced than ours could reduce our competitors' power production costs, resulting in their having a lower cost structure than is achievable with the technologies we currently employ and adversely affect our ability to compete for offtake agreement renewals. If we are unable to replace an expiring or terminated offtake agreement, the affected facility may temporarily or permanently cease operations. External events, such as a severe economic downturn, could also impair the ability of some counterparties to our offtake agreements and other customer agreements to pay for energy and/or other products and services received.

Our inability to enter into new or replacement offtake agreements or to compete successfully against current and future competitors in the markets in which we operate could have a material adverse effect on our business, financial condition, results of operations and cash flows.

Transactions with counterparties expose us to credit risk which we must effectively manage to mitigate the effect of counterparty default

We are exposed to the credit risk profile of the counterparties to our long-term concession contracts, our suppliers and our financing providers, which could impact our business, financial condition and results of operations. Although we actively manage this credit risk through diversification and other measures, our risk management strategy may not be successful in limiting our exposure to credit risk. This could adversely affect our business, financial condition, results of operations and cash flow.

We may be subject to increased finance expenses if we do not effectively manage our exposure to interest rate and foreign currency exchange rate risks

We are exposed to various types of market risk in the normal course of business, including the impact of interest rate changes and foreign currency exchange rate fluctuations. Some of our indebtedness (including project-level indebtedness) bears interest at variable rates, generally linked to market benchmarks such as EURIBOR and LIBOR. Any increase in interest rates would increase our finance expenses relating to our variable rate indebtedness and increase the costs of refinancing our existing indebtedness and issuing new debt. See "Item 5.A—Operating Results—Results of Operations—Factors Affecting our Results of Operations—Interest rates."

In addition, although most of our long-term contracts are denominated in, indexed or hedged to U.S. dollars, we conduct our business and incur certain costs in the local currency of the countries in which we operate. In addition, the revenues, costs and debt of our solar assets in Spain are denominated in euros. Since the beginning of 2017, we have euro-denominated debt at the corporate level. Interest payments in euros and our euro denominated general and administrative expenses create a natural hedge for a portion of the distributions from Spanish assets. Our strategy is to hedge the exchange rate for the distributions from our Spanish assets after deducting euro-denominated interest payments and euro-denominated general and administrative expenses. Through currency options, we hedge 100% of the net euro net exposure for the next 12 months and 75% of the net euro net exposure for the following 12 months. See "Item 5.A—Operating Results—Results of Operations—Factors Affecting our Results of Operations—Exchange Rates" and "Item 11.—Quantitative and Qualitative Disclosures about Market Risk—Foreign exchange rate risk."

As we continue expanding our business into existing markets such as South America, Europe or other markets, an increasing percentage of our revenue and cost of sales may be denominated in currencies other than our reporting currency, the U.S. dollar. Under that scenario, we would become subject to increasing currency translation risk, whereby changes in exchange rates between the U.S. dollar and the other currencies in which we do business could result in foreign exchange losses.

In addition, we seek to actively work with lending financial institutions to mitigate our interest rate risk exposure and to secure lower interest rates by entering into interest rate options and swaps. As a matter of policy, we seek to cover at least 70% of our outstanding long-term project debt.

If our risk-management strategies are not successful in limiting our exposure to changes in interest rates and foreign currency exchange rates our business, financial condition and results of operations could be materially and adversely affected.

Our competitive position could be adversely affected by changes in technology, prices, industry standards and other factors

The markets in which our assets or projects operate change rapidly because of technological innovations and changes in prices, industry standards, product instructions, customer requirements and the economic environment. New technology or changes in industry and customer requirements may put pressure on the profitability of our existing projects by increasing the incentives of counterparties to our long-term contracts to seek new alternative projects or request higher service standards.

The performance of our assets under our concession contracts may be adversely affected by problems related to our reliance on third-party contractors and suppliers

Our projects rely on the supply of services, equipment, including technologically complex equipment and software which we subcontract to Abengoa or other third-party suppliers in order to meet our contractual obligations under our contracted concessions. We rely on the equipment, design and technology of third parties to operate our assets. In circumstances where key components of our equipment, including but not limited to turbines, water pumps or transformers, fail because of design failures or faulty operation or for any other reason, we rely on third parties to continue operating our assets. In some cases, the replacement of damaged equipment can take a long period of time, which can cause our plants to curtail or cease operations during such time, which could have a negative impact in our results of operations and cash flows. We had significant interruptions in 2017 at Kaxu as a result of water pump failures and at Solana in 2017 as a result of transformer failures. In addition, in the last quarter of 2017 and the first quarter of 2018, we had temporary unavailability in some of our plants due to technical inspections of the turbines that were requested by the supplier of the turbines. Similar interruptions could happen again at Kaxu or Solana or at other plants due to failures in key equipment. Design failures, technical inspections by suppliers or need to replace key equipment can require unexpected capital expenditures and/or outages in our plants, which could have a material adverse effect on our business, results of operations, financial condition and cash flows.

In addition, the delivery of products or services which are not in compliance with the requirements of the subcontract, or the late supply of products and services, can cause us to be in default under our contracts with our concession counterparties. To the extent we are not able to transfer all of the risk or be fully indemnified by Abengoa or other third-party contractors and suppliers, we may be subject to a claim by our customers as a result of a problem caused by a third party that could have a material adverse effect on our reputation, business, results of operations, financial condition and cash flows.

Supplier concentration may expose us to significant financial credit or performance risk

We often rely on a single contracted supplier or a small number of suppliers, which in some cases are subsidiaries of Abengoa, for the provision of equipment, technology, fuel, transportation of fuel, and/or other services required for the operation of certain of our facilities. In addition, certain of our suppliers, including Abengoa and its subsidiaries, provide long-term warranties with respect to the performance of their products or services. If any of these suppliers cannot perform under their agreements with us, or satisfy their related warranty obligations, we will need to utilize the marketplace to provide or repair these products and services. There can be no assurance that the marketplace can provide these products and services as, when and where required. We may not be able to enter into replacement agreements on favorable terms or at all. If we are unable to enter into replacement agreements to provide for equipment, technology or fuel and other required services, we would seek to purchase the related goods or services at market prices, exposing us to the risk of unavailability and market price volatility. We may also be required to make significant capital contributions to remove, replace or redesign equipment that cannot be supported or maintained by replacement suppliers, which could have a material adverse effect on our business, financial condition, results of operations, credit support terms and cash flows.

The failure of any supplier or customer to fulfill its contractual obligations to us could have a material adverse effect on our financial results. Consequently, the financial performance of our facilities is dependent on the credit quality of, and continued performance by, our suppliers and vendors.

We may be adversely affected by risks associated with acquisitions or investments

As a part of our growth strategy, we intend to make certain acquisitions and/or financial investments, and we may take on additional equity and debt to pay for such acquisitions. Moreover, we cannot guarantee that we will be able to complete all, or any, such transactions that we might contemplate in the future. To the extent we do, such transactions expose us to risks inherent in integrating acquired businesses and personnel, such as the inability to achieve projected cash flows; recognition of unexpected liabilities or costs; and regulatory complications arising from such transactions. Furthermore, the terms and conditions of financing for such acquisitions or financial investments could restrict the manner in which we conduct our business, particularly if we were to use debt financing. These risks could have a material adverse effect on our business, financial condition and results of operations.

In addition, we have made and may continue to make equity investments in certain strategic assets managed by or together with third parties, including governmental entities and private entities. In certain cases, we may only have partial or joint control over a particular asset. We hold a minority stake in Honaine and do not have control over the operation of that asset. Investments in assets over which we have no, partial or joint control are subject to the risk that the other shareholders of the assets, who may have different business or investment strategies than us or with whom we may have a disagreement or dispute, may have the ability to independently make or block business, financial or management decisions, such as the decision to distribute dividends or appoint members of management, which may be crucial to the success of the project or our investment in the project, or otherwise implement initiatives which may be contrary to our interests. Additionally, the approval of other shareholders or partners may be required to sell, pledge, transfer, assign or otherwise convey our interest in such assets. Similarly, the approval of other shareholders or partners may be required to acquire AAGES', Algonquin's, Abengoa's or third parties' interests in potential acquisitions. Alternatively, other shareholders may have rights of first refusal or rights of first offer in the event of a proposed sale or transfer of our interests in such assets or in the event of our acquisition of an interest in new assets pursuant to the ROFO Agreements or with third parties. These restrictions may limit the price or interest level for our interests in such assets, in the event we want to sell such interests.

Finally, our partners in existing or future projects, including tax equity investors, may be unable, or unwilling, to fulfill their obligations under the relevant shareholder agreements, may experience financial or other difficulties or might sell their position to third parties that we did not choose, which may adversely affect our investment in a particular joint venture or adversely affect us. In certain of our joint ventures, we may also be reliant on the particular expertise of our partners and, as a result, any failure to perform our obligations in a diligent manner could also adversely affect the joint venture. If any of the foregoing were to occur, our business, financial condition, results of operations and cash flows could be materially and adversely affected.

There are risks relating to future acquisitions and investments

Our board of directors may approve acquisitions and investments at any time. This could result in our making acquisitions or investments in assets that are located in different jurisdictions and are different from, and possibly riskier than, those jurisdictions that are described in this annual report. These changes could adversely affect the market price of our shares or our ability to make distributions to shareholders.

The facilities we operate are, in some cases, dangerous workplaces at which hazardous materials are handled. If we fail to maintain safe work environments, we can be exposed to significant financial losses, as well as civil and criminal liabilities

The facilities we operate often put our employees and others in close proximity with large pieces of mechanized equipment, moving vehicles, manufacturing or industrial processes, heat or liquids stored under pressure and highly regulated materials. On most projects and at most facilities, we, together with the operations and maintenance supplier, are responsible for safety and, accordingly, must implement safe practices and safety procedures, which are also applicable to on-site subcontractors. If we or the operations and maintenance supplier fail to design and implement such practices and procedures or if the practices and procedures are ineffective or if our O&M service providers or other suppliers do not follow them, our employees and others may become injured and our and others' property may become damaged. Unsafe work sites also have the potential to increase employee turnover, increase the cost of a project to our customers or the operation of a facility, and raise our operating costs. Any of the foregoing could result in financial losses, which could have a material adverse effect on our business, financial condition, results of operations and cash flows.

In addition, our projects and the operation of our facilities can involve the handling of hazardous and other highly regulated materials, which, if improperly handled or disposed of, could subject us or our suppliers to civil and criminal liabilities. We are also subject to regulations dealing with occupational health and safety. Although we maintain functional groups whose primary purpose is to ensure we implement effective health, safety and environmental work procedures throughout our organization, the failure to comply with such regulations could subject us to liability. In addition, we may incur liability based on allegations of illness or disease resulting from exposure of employees or other persons to hazardous materials that we handle or are present in our workplaces.

The operation and maintenance of most of our assets is labor intensive, work stoppages by employees could harm our business

The operation and maintenance of most of our assets is labor intensive and our operators' employees are covered by collective bargaining agreements. A dispute with a union or employees represented by a union could result in production interruptions caused by work stoppages. If a strike or work stoppage were to occur, our results of operations could be adversely affected.

Our business may be adversely affected by catastrophes, natural disasters, adverse weather conditions, climate change, unexpected geological or other physical conditions, or criminal or terrorist acts at one or more of our plants, facilities and electric transmission lines

If one or more of our plants, facilities or electric transmission lines were to be subject in the future to fire, flood, extreme weather conditions (including severe wind), earthquakes or other natural disaster, adverse weather conditions, drought, terrorism, power loss or other catastrophe, or if unexpected geological or other adverse physical conditions (including earthquakes) were to develop at any of our plants, facilities or electric transmission lines, we may not be able to carry out our business activities at that location or such operations could be significantly reduced. For example, drought may affect the cooling capacity of our concentrating solar power projects. Any of these circumstances could result in lost revenue at these sites during the period of disruption and costly remediation, which could have a material adverse effect on our business, financial condition, results of operations and cash flows. In addition, despite security measures taken by us, it is possible that our sites and assets could be affected by criminal or terrorist acts. Any such acts could have a material adverse effect on our business, financial condition, results of operations and cash flows.

Our insurance may be insufficient to cover relevant risks and the cost of our insurance may increase

Our business is exposed to the inherent risks in the markets in which we operate. Although we seek to obtain appropriate insurance coverage in relation to the principal risks associated with our business, we cannot guarantee that such insurance coverage is, or will be, sufficient to cover all of the possible losses we may face in the future. If we were to incur a serious uninsured loss or a loss that significantly exceeded the coverage limits established in our insurance policies, the resulting costs could have a material adverse effect on our business, financial condition, results of operations and cash flows.

In addition, our insurance policies are subject to review by our insurers. If insurance premiums were to increase in the future, if certain types of insurance coverage were to become unavailable or there was an increase in deductibles for damages and/or loss of production, it could have an adverse effect on our ability to comply with our obligations to the lenders in our project finance agreements. In addition, we might not be able to maintain insurance coverage comparable to those that are currently in effect at comparable cost, or at all. If we were unable to pass any increase in insurance premiums on to our customers, such additional costs could have a material adverse effect on our business, financial condition, results of operations and cash flows.

We may be subject to litigation and other legal proceedings

We are subject to the risk of legal claims and proceedings, requests for arbitration as well as regulatory enforcement actions in the ordinary course of our business and otherwise, including claims against our subsidiaries related to Abengoa or its subsidiaries not meeting its obligations. The results of legal and regulatory proceedings cannot be predicted with certainty. We cannot guarantee that the results of current or future legal or regulatory proceedings or actions will not materially harm our business, financial condition, results of operations or operations, nor can we guarantee that we will not incur losses in connection with current or future legal or regulatory proceedings or actions that exceed any provisions we may have set aside in respect of such proceedings or actions or that exceed any available insurance coverage, which may have a material adverse effect on our business, financial condition, results of operations and cash flows. See "Item 4.B—Business Overview—Legal Proceedings."

We are subject to reputational risk, and our reputation is closely related to that of Abengoa and Algonquin

We rely on our reputation to do business, obtain financing, hire and retain employees and attract investors, one or more of which could be adversely affected if our reputation were damaged. Harm to our reputation could arise from real or perceived faulty or obsolete technology, failure to comply with legal and regulatory requirements, difficulties in meeting contractual obligations or standards of quality and service, ethical issues, money laundering and insolvency, among others.

Our reputation is still affected by Abengoa's reputation. The public image and reputation of Abengoa have suffered as a result of its financial condition and its restructuring process. We have been adversely affected due to our relationship with Abengoa. Any further developments with respect to Abengoa's financial condition or operating performance or any failure by Abengoa to satisfactorily resolve the proceedings discussed below could further harm our reputation, which could have an adverse effect on our business, financial condition and results of operations. See "Item 3D.—Risks Related to Our Relationship with Abengoa."

In addition, Algonquin will become our largest shareholder upon completion of the Share Sale, for which all conditions precedent have been satisfied and for which the parties have commenced the process for the transfer of our shares, which we expect to close in the upcoming days. As a result of Algonquin becoming or largest shareholder and sponsor, our reputation is also affected by Algonquin's reputation. If the public image or reputation of Algonquin were to be damaged as a result of adverse publicity, poor financial or operating performance, changes in financial condition, decline in the price of its shares or otherwise, we could be adversely affected, which could have an adverse effect on our business, financial condition and results of operations.

The loss of one or more of our executive officers or key employees may adversely affect our ability to effectively manage our projects

We depend on our experienced management team and the loss of one or more key executives may negatively affect our business. We also depend on our ability to retain and motivate key employees and attract qualified new employees. We may not be able to replace departing members of our management team or key employees. Integrating new executives into our management team and training new employees with no prior experience in our industry could prove disruptive to our projects, require a disproportionate amount of resources and management attention and ultimately prove unsuccessful. An inability to attract and retain sufficient technical and managerial personnel could limit our ability to effectively manage our projects, which could have a material adverse effect on our business, financial condition, results of operations and cash flows.

We utilize information technology and communications systems to run our business, the failure of which could significantly impact our operations and business

We are dependent upon information technology systems in the conduct of our operations. Our information technology systems are subject to disruption, damage or failure from a variety of sources, including, without limitation, computer viruses, security breaches, cyber-attacks, phishing attacks, natural disasters and defects in design. Recently, energy facilities are experiencing an increased number of cyber-attacks. Cybersecurity incidents, in particular, are evolving and include malicious software, attempts to gain unauthorized access to data and other electronic security breaches that could lead to disruptions in systems, unauthorized release of confidential or otherwise protected information and the corruption of data. Various measures have been implemented to minimize our risks related to information technology systems and network disruptions. However, given the unpredictability of the timing, nature and scope of information technology disruptions, we could potentially be subject to production downtimes, operational delays, the compromising of confidential or otherwise protected information, destruction or corruption of data, security breaches, other manipulation or improper use of our systems and networks or financial losses from remedial actions, any of which could have a material adverse effect on our cash flows, competitive position, financial condition or results of operations.

We maintain global information technology and communication networks and applications to support our business activities. Information technology security processes may not prevent future malicious actions, denial-of-service attacks, or fraud, resulting in corruption of operating systems, theft of commercially sensitive data, misappropriation of funds and business and operational disruption. Material system breaches and failures could result in significant interruptions that could in turn affect our operating results and reputation.

Risks Related to Our Assets

The concession agreements or power purchase agreements under which we conduct some of our operations are subject to revocation or termination

Certain of our operations are conducted pursuant to contracted concessions granted by various governmental bodies. Generally, these contracted concessions give us rights to provide services for a limited period of time, subject to various governmental regulations. The governmental bodies or private clients responsible for regulating and monitoring these services often have broad powers to monitor our compliance with the applicable concession contracts and can require us to supply them with technical, administrative and financial information. Among other obligations, we may be required to comply with operating targets and efficiency and safety standards established in the concession. Such commitments and standards may be amended in certain cases by the governmental bodies. Our failure to comply with the concession agreements or other regulatory requirements may result in contracted concessions being revoked, not being granted, upheld or renewed in our favor, or, if granted, upheld or renewed, may not be done on as favorable terms as currently applicable. This could have a material adverse effect on our business, financial condition, results of operations and cash flows.

In some of the markets in which we are present, or in which we may own assets in the future, political instability, economic crisis or social unrest may give rise to a change in policies regarding long-term contracted assets with private companies, like us, in strategic sectors such as power generation, electric transmission or water. Any such changes could lead to modifications of the economic terms of our concession contracts or, in extreme scenarios, the nationalization of our assets, which could have a material adverse effect on our business, financial condition, results of operations and cash flows.

Revenues in our solar assets in Spain are mainly defined by regulation and some of the parameters defining the remuneration are subject to review every six years

In 2013, the Spanish government modified regulations applicable to renewable energy assets, including solar power. According to Royal Decree 413/2014, solar electricity producers in Spain receive: (i) the pool price for the power they produce and (ii) a payment based on the standard investment cost for each type of plant (without any relation whatsoever to the amount of power they generate). This payment based on investment (in €/MW of installed capacity) is supplemented, in the case of solar plants, by an “operating payment” (in €/MWh produced).

The principle driving this economic regime is that the payments received by a renewable energy producer should be equivalent to the costs that they are unable to recover on the electricity pool market where they compete with non-renewable technologies. This economic regime seeks to allow a “well-run and efficient enterprise” to recover the costs of building and running a plant, plus a reasonable return on investment (project investment rate of return). This reasonable return is currently calculated as the average yield on Spanish government 10-year bonds on the secondary market in a 24-month period preceding the new regulatory period, plus a spread depending on the Government’s decision based on the following indicative criteria:

- Appropriate profit for this specific type of renewable electricity generation and electricity generation as a whole, considering the financial condition of the Spanish electricity system and Spanish prevailing economic conditions; and

- Borrowing costs for electricity generation companies using renewable energy sources with regulated payment systems, which are efficient and well run, within Europe.

Payment criteria are based on prevailing economic conditions in Spain, demand for electricity and reasonable profits for electricity generation activities and can be revised every six years at the end of each regulatory period. The first regulatory period commenced on July 14, 2013, the date on which Royal Decree-law 9/2013 came into force and will end on December 31, 2019. The values of parameters used to calculate the payments can be changed at the end of each regulatory period, except for a plant’s useful life and the value of a plant’s initial investment. Unless reviewed, payment criteria will be considered to be extended for the subsequent regulatory period.

If the payments for renewable energy plants are revised to lower amounts in the next regulatory period starting on January 1, 2020 until December 31, 2025, this could have a material adverse effect on our business, financial condition, results of operations and cash flows. As a reference, assuming our Spanish assets continue to perform as expected and assuming no additional changes of circumstances, with the information currently available we estimate that a reduction of 100 basis points in the reasonable rate of return on investment set by the Spanish government could cause a reduction in our cash available for distribution of approximately €18 million per year. This estimate is subject to certain assumptions, which may change in the future.

Revenue from our contracted assets and concessions is significantly dependent on regulated tariffs or other long-term fixed rate arrangements that restrict our ability to increase revenue from these operations

The revenue that we generate from our contracted concessions is significantly dependent on regulated tariffs or other long-term fixed rate arrangements. Under most of our concession agreements, a tariff structure is established in such agreements, and we have limited or no possibility to independently raise tariffs beyond the established rates and indexation or adjustment mechanisms. Similarly, under a long-term PPA, we are required to deliver power at a fixed rate for the contract period, in some cases with predefined escalation rights. In addition, we may be unable to adjust our tariffs or rates as a result of fluctuations in prices of raw materials, exchange rates, labor and subcontractor costs during the operating phase of these projects, or any other variations in the conditions of specific jurisdictions in which our concession-type infrastructure projects are located, which may reduce our profitability. Moreover, in some cases, if we fail to comply with certain pre-established conditions, the government or customer (as applicable) may reduce the tariffs or rates payable to us. In addition, during the life of a concession, the relevant government authority may unilaterally impose additional restrictions on our tariff rates, subject to the regulatory frameworks applicable in each jurisdiction. Governments may also postpone annual tariff increases until a new tariff structure is approved without compensating us for lost revenue. Furthermore, changes in laws and regulations may, in certain cases, have retroactive effect and expose us to additional compliance costs or interfere with our existing financial and business planning.

Revenue from our renewable energy and efficient natural gas (previously named “conventional”) power facilities is partially exposed to market electricity prices

In addition to regulated incentives, revenue and operating costs from certain of our projects depend to a limited extent on market prices for sales of electricity. Market prices may be volatile and are affected by various factors, including the cost of raw materials, user demand, and if applicable, the price of greenhouse gas emission rights. In several of the jurisdictions in which we operate, we are exposed to remuneration schemes which contain both regulated incentive and market price components. In such jurisdictions, the regulated incentive component may not compensate for fluctuations in the market price component, and, consequently, total remuneration may be volatile. There can be no assurance that market prices will remain at levels which enable us to maintain profit margins and desired rates of return on investment. A decline in market prices below anticipated levels could have a material adverse effect on our business, financial condition, results of operations and cash flows.

Our solar and wind projects will be negatively affected if there are adverse changes to national and international laws and policies that support renewable energy sources

Certain countries, such as the United States, a market that is one of our principal markets, have in recent years enacted policies of active support for renewable energy. These policies have included feed-in tariffs and renewable energy purchase obligations, mandatory quotas and/or portfolio standards imposed on utilities and certain tax incentives (such as ITCs in the United States). See “Item 4.B—Business Overview—Regulation—Regulation in the United States—Federal Considerations for Renewable Energy Generation Facilities—Section 1603 U.S. Treasury Grant Program.”

Certain policies currently in place may expire, be suspended or be phased out over time, cease upon exhaustion of the allocated funding or be subject to cancellation or non-renewal, particularly if the cost of renewable energy exceeds the cost of generation of energy from other means. Accordingly, we cannot guarantee that such government support will be maintained in full, in part or at all. See “—Government regulations providing incentives and subsidies for renewable energy could change at any time, including pursuant to the proposed environmental and tax policies of the current administration in the United States, and such changes may negatively impact our growth strategy.”

If the governments and regulatory authorities in the jurisdictions in which we operate or plan to operate were to further decrease or abandon their support for development of solar and wind energy due to, for example, competing funding priorities, political considerations or a desire to favor other energy sources, renewable or otherwise, the assets we plan to acquire in the future could become less profitable or cease to be economically viable. Such an outcome could have a material adverse effect on our ability to execute our growth strategy.

The results of the 2016 U.S. presidential and congressional elections have created regulatory uncertainty for the alternative energy sector

U.S. political developments have created regulatory uncertainty in the renewable energy sector. President Trump has withdrawn the United States from the U.N. Framework Convention on Climate Change designed to curtail global warming. If President Trump and/or the U.S. Congress take further action or publicly speak out about the need to eliminate or further reduce legislation, regulations and incentives supporting renewable energy, such actions may result in a decrease in demand for renewable energy in the United States and may materially harm our business, financial condition and operating results.

Lack of electric transmission capacity availability, potential upgrade costs to the electric transmission grid, and other systems constraints could significantly impact our ability to generate solar electricity power sales

We depend on electric interconnection and transmission facilities owned and operated by others to deliver the wholesale power we sell from our electric generation assets to our customers. A failure or delay in the operation or development of these interconnection or transmission facilities or a significant increase in the cost of the development of such facilities could result in the loss of revenues. Such failures or delays could limit the amount of power our operating facilities deliver or delay the completion of our construction projects, as the case may be. Additionally, such failures, delays or increased costs could have a material adverse effect on our business, financial condition, results of operations and cash flows. If a region's electric transmission infrastructure is inadequate, our recovery of wholesale costs and profits may be limited. If restrictive transmission price regulation is imposed, the transmission companies may not have a sufficient incentive to invest in expansion of transmission infrastructure. Additionally, we cannot predict whether interconnection and transmission facilities will be expanded in specific markets to accommodate competitive access to those markets. In addition, certain of our operating facilities' generation of electricity may be curtailed without compensation due to transmission limitations or limitations on the electricity grid's ability to accommodate intermittent electricity generating sources, reducing our revenues and impairing our ability to capitalize fully on a particular facility's generating potential. Such curtailments could have a material adverse effect on our business, financial condition, results of operations and cash flows.

We do not own all of the land on which our renewable energy, efficient natural gas (previously named "conventional") power or electric transmission assets are located, which could result in disruption to our operations

We do not own all of the land on which our power generation or electric transmission assets are located, and we are, therefore, subject to the possibility of less desirable terms and increased costs to retain necessary land use if we do not have valid leases or rights-of-way or if such rights-of-way lapse or terminate. Although we have obtained rights to construct and operate these assets pursuant to related lease arrangements, our rights to conduct those activities are subject to certain exceptions, including the term of the lease arrangement. Our loss of these rights, through our inability to renew right-of-way contracts or otherwise, may adversely affect our ability to operate our power generation and electric transmission assets.

Certain of our facilities may not perform as expected

Our expectations regarding the operating performance of certain assets, particularly Solana and Kaxu, are based on assumptions, estimates and past experience with similar assets that Abengoa has developed and built, and without the benefit of a substantial operating history. Our projections regarding our ability to generate cash available for distribution and to pay dividends to holders of our shares assume facilities perform in accordance to our expectations. However, the ability of these facilities to meet our performance expectations is subject to the risks inherent in power generation facilities and the construction of such facilities, including, but not limited to, degradation of equipment in excess of our expectations, system failures and outages. The failure of these facilities to perform as we expect could have a material adverse effect on our business, financial condition, results of operations and cash flows and our ability to pay dividends to holders of our shares.

In the case of Solana, we have a partnership with Liberty Interactive Corporation, or Liberty, pursuant to which Liberty agreed to invest $300 million in the parent company of the project entity, in exchange for the right to receive 61.20% of taxable losses and distributions until such time as Liberty reaches a certain rate of return, or the “Flip Date,” and 22.60% of taxable losses and distributions thereafter. Given the underperformance of the asset in the last years, we cannot assure the Flip Date will occur or when it will occur. If the Flip Date never occurs or if there is a delay, this can adversely affect the cash flows expected from that project.

The generation of electric energy from renewable energy sources depends heavily on suitable meteorological conditions, and if solar or wind conditions are unfavorable, our electricity generation, and therefore revenue from our renewable energy generation facilities using our systems, may be substantially below our expectations

The electricity produced, and revenues generated by a renewable energy generation facility are highly dependent on suitable solar or wind conditions, as applicable, and associated weather conditions, which are beyond our control. Furthermore, components of our system, such as structures, mirrors, absorber tubes or blades, could be damaged by severe weather. In addition, replacement and spare parts for key components may be difficult or costly to acquire or may be unavailable.

Unfavorable weather and atmospheric conditions could impair the effectiveness of our assets or reduce their output beneath their rated capacity or require shutdown of key equipment, impeding operation of our renewable assets and our ability to achieve forecasted revenues and cash flows. As climate change increases the frequency and severity of severe weather conditions and may have the long-term effect of changing meteorological conditions at our project sites, such impairments may increase in frequency and/or severity.

We base our investment decisions with respect to each renewable generation facility on the findings of related wind and solar studies conducted on-site by third parties prior to construction or based on historical conditions at existing facilities. However, actual climatic conditions at a facility site, particularly wind conditions, which are sometimes severe, may not conform to the findings of these studies and therefore, our solar and wind energy facilities may not meet anticipated production levels or the rated capacity of our generation assets, which could adversely affect our business, financial condition and results of operations and cash flows.

Our costs, results of operations, financial condition and cash flows could be adversely affected by the disruption of the fuel supplies necessary to generate power at our efficient natural gas (previously named “conventional”) generation facilities

Delivery of fossil fuels to fuel our efficient natural gas and some solar power generation facilities is dependent upon the infrastructure, including natural gas pipelines, available to serve each such generation facility, as well as upon the continuing financial viability of contractual counterparties. As a result, we are subject to the risks of disruptions or curtailments in the production of power at these generation facilities if a counterparty fails to perform or if there is a disruption in the relevant fuel delivery infrastructure.

Maintenance, expansion and refurbishment of electric generation facilities involve significant risks that could result in unplanned power outages or reduced output

Although the facilities in our portfolio are relatively new, they may require periodic upgrading and improvement in the future. Any unexpected operational or mechanical failure, including failure associated with breakdowns and forced outages, could reduce our facilities’ generating capacity below expected levels, reducing our revenues and jeopardizing our ability to pay dividends to shareholders at forecasted levels or at all. Degradation of the performance of our solar facilities above levels provided for in the related offtake agreements may also reduce our revenues. Unanticipated capital expenditures associated with maintaining, upgrading or repairing our facilities may also reduce profitability.

If we make any major modifications to our efficient natural gas or renewable power generation facilities or electric transmission lines, we may be required to comply with more stringent environmental regulations, which would likely result in substantial additional capital expenditures. We may also choose to repower, refurbish or upgrade our facilities based on our assessment that such activity will provide adequate financial returns. Such facilities require time for development and capital expenditures before commencement of commercial operations, and key assumptions underpinning a decision to make such an investment may prove incorrect, including assumptions regarding construction costs, timing, available financing and future fuel and power prices. This could have a material adverse effect on our business, financial condition, results of operations and cash flows.

Risks Related to Our Relationship with Abengoa

Abengoa recently completed a restructuring and we cannot guarantee that they will be successful

On November 27, 2015, Abengoa reported that it filed a communication pursuant to article 5 bis of the Spanish Insolvency Law 22/2003 with the Mercantile Court of Seville nº 2.

On September 24, 2016, Abengoa announced that it signed a restructuring agreement with a group of investors and creditors, which included a commitment from investors and banks to contribute new money to Abengoa. On March 31, 2017, Abengoa announced the completion of the restructuring. In addition, Abengoa has announced publicly that it has arranged a process for the divestiture of the shares it owns in us. See “Item 4.A History and Development of the Company–Our largest shareholders Algonquin and Abengoa.”

As of December 31, 2016, the financing arrangement of Kaxu contained cross-default provisions related to Abengoa such that debt defaults by Abengoa, subject to certain threshold amounts and/or a restructuring process, could trigger default under such project financing arrangement. In March 2017, we obtained a waiver in our Kaxu project financing arrangement which waives any potential cross-defaults with Abengoa up to that date, but it does not cover potential future cross-default events.

In addition, as of December 31, 2016, the financing arrangements of Kaxu, ACT, Solana and Mojave contained a change of ownership clause that would be triggered if Abengoa ceased to own at least 35.0% of Atlantica’s shares (30.0% in the case of Solana and Mojave). If Abengoa ceased to comply with its obligation to maintain a minimum ownership of Atlantica’s shares, such reduced ownership would put us in breach of covenants under the project financing arrangements.

• In the case of Kaxu, in March 2017, we and Kaxu’s lenders entered into a waiver that allows a reduction of ownership by Abengoa below the 35.0% threshold if it occurs in the context of Abengoa’s restructuring plan, which includes the sale to Algonquin.

• In the case of ACT, in October 2017, we obtained a waiver from the lenders of the project finance agreement. The financing agreement was amended to delete the minimum ownership clause related to Abengoa.

• In the case of Solana and Mojave, a forbearance agreement signed with the DOE in 2016 with respect to these assets allows reductions of Abengoa’s ownership of our shares if it results from (i) a sale or other disposition at any time pursuant to and in connection with a subsequent insolvency proceeding by Abengoa, or (ii) capital increases by us. In other events of reduction of ownership by Abengoa below the minimum ownership threshold such as sales of shares by Abengoa, the available DOE remedies will not include debt acceleration, but DOE remedies available could include limitations on distributions to us from Solana and Mojave. In addition, the minimum ownership threshold for Abengoa’s ownership of our shares has been reduced from 35.0% to 30.0%. In November 2017, in the context of the agreement reached between Abengoa and Algonquin for the acquisition by Algonquin of 25.0% of our shares and based on the obligations of Abengoa under an EPC contract, we signed a consent in relation to the Solana and Mojave projects which reduces the minimum ownership required by Abengoa in us from 30.0% to 16.0%, subject to certain conditions precedent. In Solana, the EPC guarantee period expired without reaching the expected production. As the EPC supplier, Abengoa agreed to provide certain compensations. As a result, the main conditions precedent included several payments by Abengoa to Solana before December 2017 and February 2018 (subsequently postponed to May 2018), for a total amount of $120 million. Additionally, Abengoa has recognized other obligations to Solana for $6.5 million per half-year over 10 years starting in December 2018. In December 2017, Solana received $42.5 million which was used to repay project finance debt. Solana is expected to receive in March 2018 an additional $77.5 million. From this amount $52.5 million are expected to be used to repay project debt and $25 million are expected to cover other current and potential future Abengoa obligations. We cannot guarantee Abengoa will be able to fulfil its obligations to Solana for $6.5 million per half-year over 10 years starting in December 2018. If Solana does not receive the payments agreed and/or if Abengoa does not deliver on its existing obligations as an EPC supplier, Solana may have a negative financial impact or may not reach its target production, which could have a material adverse effect on our results of operations and cash flows.

Based on the most recent public information, Abengoa currently owns 41.47% of our shares and upon completion of the Share Sale, will own 16.47% of our shares, all of which are pledged as collateral under their New Money 1 Tradable Notes and loans. If Abengoa ceases to maintain its 16.0% ownership of Atlantica's shares, such reduced ownership would put us in breach of covenants under the Solana and Mojave project financing arrangements.

We have not identified any PPAs or any contracts with offtakers that include any cross-default provision relating to Abengoa or any minimum ownership provision.

Neither our Revolving Credit Facility nor our Note Issuance Facility includes a cross-default provision related to Abengoa. They include, however, a cross-default provision related to a default by our project subsidiaries in their financing arrangements, such that a payment default by one or more of our non-recourse subsidiaries representing more than 20% of the cash available for distribution distributed in the previous four fiscal quarters could trigger a default under our Revolving Credit Facility and our Note Issuance Facility. Additionally, under the terms of our Revolving Credit Facility, we are required to comply with (i) a maintenance leverage ratio of our indebtedness at the holding level to our cash available for distribution of 5.00:1.00 on and after January 1, 2018, and (ii) an interest coverage ratio of 2.00:1.00 of cash available for distribution to debt service payments for the duration of the Agreement. Under the terms of our Note Issuance Facility, we are required to comply with (i) a maintenance leverage ratio of our indebtedness to our cash available for distribution of 5.00:1.00 on and after January 1, 2017, and of 4.75:1.00 on and after January 1, 2020, and (ii) a debt service coverage ratio of 2.00:1.00 of cash available for distribution to debt service payments. A payment default in several of our project companies or restrictions in distributions from several of our project companies may trigger these covenants.

Furthermore, although we have separated our IT systems from Abengoa's, we still rely on some of Abengoa's operational IT systems and communications systems in some of our assets. If Abengoa is unsuccessful in its restructuring, it could have a material adverse effect on our business, financial condition, results of operations and cash flows.

Abengoa's financial condition could affect its ability to maintain existing guarantees and letters of credit under the Financial Support Agreement

We expect that Abengoa's financial condition could affect its ability to comply with its obligations under the Financial Support Agreement. Any failure by Abengoa to meet its obligations under such agreement could adversely affect our business or the operation of our facilities and have a material adverse effect on our business, financial condition, results of operations and cash flows. We depend on Abengoa to maintain certain existing guarantees and letters of credit in our favor under the Financial Support Agreement. Even if Abengoa were to sell our shares, it would still be liable under these agreements. If Abengoa were to fail to provide the requisite financial support, we would need to replace the financial guarantees provided by Abengoa and we may be unable to substitute guarantees and letters of credit from a third party on comparable terms, without undue delay or at all. In July 2017, we issued financial guarantees amounting to $112 million in favor of the off-takers of some of our projects, which were previously issued by Abengoa. In addition, as disclosed in our Annual Consolidated Financial Statements, we have current and future collection rights with certain subsidiaries of Abengoa. Additionally, Abengoa has a number of obligations which have resulted or could result in additional liability obligations to us or our assets. Inability of Abengoa to pay their obligations when due would have a negative impact on our current or future cash position.

Abengoa's financial condition could affect its ability to satisfy its obligations under operation and maintenance agreements, warranties and guarantees in certain assets, including production guarantees, pursuant to EPC contracts, as well as other contracts in place

In spite of its recent restructuring, a decline in the financial situation of Abengoa and of certain of its subsidiaries could result in a material adverse effect on our operation and maintenance agreements. Abengoa provides operation and maintenance services for many of our assets. We cannot guarantee that Abengoa and/or its subcontractors will be able to continue performing with the same level of service and under the same terms and conditions, and at the same prices. Although we have long-term operation and maintenance agreements with Abengoa for many of our assets, if Abengoa cannot continue performing current services at the same prices, we may need to renegotiate contracts and pay higher prices or have a change in services. In addition, this could cause us to change suppliers, or to pay higher prices or change the level of services. This could have a material adverse effect on our business, results of operations, financial situation and cash flows.

A decline in the financial situation of Abengoa could also result in a material adverse effect on Abengoa's and its subsidiaries' obligations, warranties and guarantees, including production guarantees, pursuant to certain EPC contracts, the Financial Support Agreement or any other agreement. In addition, Abengoa represented that further to the accession to the restructuring agreement, Atlantica would not be a guarantor of any obligation of Abengoa with respect to third parties and agreed to indemnify the Company for any penalty claimed by third parties resulting from any breach in such representations.

There may be unanticipated consequences of further restructuring by Abengoa or ongoing bankruptcy proceedings by Abengoa's subsidiaries that we have not yet identified. Although we have engaged in extensive contingency plans, we have also hired specialized external counsel in several jurisdictions and to the best of our knowledge, the risks of a potential bankruptcy by Abengoa are known and disclosed, nevertheless, there are uncertainties as to how any further bankruptcy proceeding would be resolved and how our relationship with Abengoa would be affected following the initiation or resolution of any such proceedings.

Algonquin and Abengoa are our largest shareholders and exercise substantial influence over us

Upon completion of the Share Sale, for which all conditions precedent have been satisfied and for which the parties have commenced the process for the transfer of our shares, which we expect to close in the upcoming days, Algonquin will beneficially own and will be entitled to vote approximately 25.0% of our ordinary shares and Abengoa will beneficially own and will be entitled to vote approximately 16.47% of our ordinary shares. As a result of this ownership, Algonquin and Abengoa will have substantial influence on our affairs and its ownership interest and voting power constitute a significant percentage of the shares eligible to vote on any matter requiring the approval of our shareholders. Such matters include the election of directors, the adoption of amendments to our articles of association and approval of mergers or sale of all or a high percentage of our assets. This concentration of ownership may also have the effect of discouraging others from making tender offers for our shares. There can be no assurance that the interests of Algonquin or Abengoa will coincide with the interests of the purchasers of our shares or that Algonquin or Abengoa will act in a manner that is in our best interests. If either Algonquin or Abengoa sells its shares of Atlantica Yield to a single shareholder, that new shareholder could continue to exercise substantial influence and could seek to influence or change our strategy or corporate governance or could take effective control of us. In addition, we did not have a prior relationship with Algonquin and we have limited knowledge and visibility of their operations and plans.

We may not be able to consummate future acquisitions from AAGES, Algonquin or Abengoa

Our ability to grow through acquisitions depends, in part, on AAGES' and Abengoa's ability to present us with acquisition opportunities. Abengoa has undergone a restructuring process in recent years. See "Item 4.A—History and Development of the Company—Our largest shareholders Algonquin and Abengoa." AAGES or Abengoa may have financial and resource constraints limiting or eliminating their ability to continue building the contracted assets which are currently under construction and may have financial and resource constraints limiting or eliminating their ability to develop and build new contracted assets. In addition, AAGES or Abengoa may sell assets under development and, in the case of Abengoa, under construction, before they reach their commercial operation date.

In addition, AAGES and Algonquin may not offer us assets at all or may not offer us assets that fit within our portfolio or contribute to our growth strategy. Only certain assets outside the United States and Canada are included in the Algonquin ROFO. Furthermore, Algonquin can terminate its ROFO agreement with us with a 180-day notice.

Additionally, we may not reach an agreement on the price of assets offered by AAGES, Algonquin or Abengoa. For these reasons, we may not be able to consummate future acquisitions from AAGES, Algonquin or Abengoa and restrict our ability to grow.

Abengoa may be forced to initiate a bankruptcy filing under Spanish Insolvency law and, as a result, it may be subject to insolvency claw-back actions in which transactions may be set aside

Under Spanish insolvency law, the transactions a company has entered into during the two years prior to the opening of insolvency proceedings can be set aside, irrespective of whether there was intent to defraud, if those transactions are considered materially damaging to the insolvency estate. Material damage is assessed on the basis of the circumstances at the time the transaction was carried out, without the benefit of hindsight and without considering subsequent events or occurrences, including events in relation to insolvency proceedings or the request to set-aside the transaction. Though we could be considered a “connected person” for purposes of Spanish bankruptcy proceedings (which triggers a presumption of damage), transactions we have entered into with Abengoa in the previous two years before it is declared insolvent (if such action were to take place) would not automatically be set aside. The court would consider if the transactions were detrimental to Abengoa on the terms on which they were made and the suitability of the transactions at the time they were entered into, if the transaction followed market standards and prices, had real economic value and if a transaction was carried out on the same conditions as it would have been by independent parties.

In practice, transactions that are subject to claw-back that usually affect companies in the same group relate to: (a) unjustified payments or advances from the insolvent company to another group company, (b) transfers of assets or rights by the insolvent company to another group company at below market value, (c) payment-in-kind arrangements in which the property another group company receives in payment is higher in value than the debt owed to it, and (d) security provided by the insolvent company for another group company’s obligations. This determination will be a question of fact before a Spanish court if Abengoa initiates a bankruptcy filing in Spain, however if any of the transactions entered into between ourselves and Abengoa, including those related to drop-downs assets, were declared invalid by a Spanish court, unless it is determined we acted in bad faith, such transaction would be unwound and we would receive back the cash paid, which could have a material adverse effect on our business, prospects, results of operations and financial condition.

The outcome of any bankruptcy proceedings that may be initiated by Abengoa would be difficult to predict given that Abengoa is incorporated in Spain and has assets and operations in several countries around the world. In the event of any bankruptcy or similar proceeding involving Abengoa or any of its subsidiaries, bankruptcy laws other than those of Spain could apply. The rights of Abengoa’s creditors may be subject to the laws of a number of jurisdictions and such multi-jurisdictional proceedings are typically complex and often result in substantial uncertainty. In addition, the bankruptcy and other laws of such jurisdictions may be materially different from, or in conflict with, one another. If Abengoa is subject to U.S. bankruptcy law, bankruptcy courts in the United States may seek to assert jurisdiction over all of its assets, wherever located, including property situated in other countries.

A bankruptcy filing by Abengoa may permanently affect Abengoa’s operations. We cannot predict how any bankruptcy proceeding would be resolved or how our relationship with Abengoa will be affected following the initiation of any such proceedings or after the resolution of any such proceedings. Any bankruptcy proceedings initiated by Abengoa may have material adverse effects on our business, prospects, results of operations and financial condition.

Our ownership structure and certain service agreements may create significant conflicts of interest that may be resolved in a manner that is not in our best interests or the best interests of our minority shareholders

Our ownership structure involves a number of relationships that may give rise to certain conflicts of interest between us, Algonquin, Abengoa and the rest of our shareholders. Three of our directors are affiliated with Abengoa and will be affiliated with Algonquin or Abengoa upon completion of the Share Sale. Additionally, operation and maintenance services are provided by subsidiaries of Abengoa for many of our assets, and some of our subsidiaries still have back-office services agreements in place with subsidiaries of Abengoa.

Upon completion of the Share Sale, for which all conditions precedent have been satisfied and for which the parties have commenced the process for the transfer of our shares, which we expect to close in the upcoming days, AAGES, Abengoa and Algonquin will be related parties under the applicable securities laws governing related party transactions and may have interests that differ from our interests or those of our other minority shareholders, including with respect to the types of acquisitions made, the timing and amount of dividends paid by us, the reinvestment of returns generated by our operations, the use of leverage when making acquisitions and the appointment of outside advisors and service providers. Any transaction between us and AAGES, Algonquin or Abengoa (including the acquisition of any ROFO assets) is subject to our related party transaction policy, which requires prior approval of such transaction by a majority of the non-conflicted directors, typically our independent directors (as discussed in “Item 7.B—Related Party Transactions—Related Party Transactions Policy—Procedures for Review, Approval and Ratification of Related Party Transactions; Conflicts of Interest”). The existence of our related party transaction approval policy may not insulate us from derivative claims related to related party transactions and the conflicts of interest described in this risk factor. Regardless of the merits of such claims, we may be required to spend significant management time and financial resources in the defense thereof. Additionally, to the extent we fail to appropriately deal with any such conflicts, it could negatively impact our reputation and ability to raise additional funds and the willingness of counterparties to do business with us, all of which could have a material adverse effect on our business, financial condition, results of operations and cash flows.

Abengoa’s sales of our shares may increase the risk of divergence of interest between us and Abengoa

As a result of its reduction of its ownership of us, Abengoa has less incentive than previously to advance our interests. Even if Abengoa sells all of our shares that it owns, Abengoa is still required to continue to satisfy its contractual obligations under the current contracts with us including the operation and maintenance agreements, the Financial Support Agreement and limited support service agreements in Peru and South Africa. If Abengoa fails to comply with its obligations or terminates operation and maintenance agreements, we would need to find alternative suppliers or alternative ways to perform those services and we cannot be certain that the service level, payment conditions or cost would be comparable to the current O&M contracts with Abengoa, especially in regard to assets with “all in” pricing arrangements. Abengoa also has a number of obligations in several assets as an EPC supplier irrespective of its ownership in us. In Kaxu and Solana, the EPC guarantee periods have expired without reaching the guaranteed production. In Kaxu, we have reached an agreement with Abengoa and the lenders under the project financing agreement to extend the production guarantee until October 2018.

A change of control may have negative implications for us

Abengoa has communicated that, once the Share Sale is complete, it intends to sell its 16.47% stake in us; if the buyer of Abengoa’s stake in us (or another investor) acquires more than 50.0% of our shares, we might need to refinance all or part of our corporate debt or obtain waivers from the lending financial institutions, due to the fact that they contain customary change of control provisions. Additionally, we could see an increase in the yearly state property tax payment in Mojave, which would be evaluated by the tax authority at the time the change of control potentially occurred. Our best estimate with current information available and subject to further analysis is that we could have an incremental annual payment of property tax of approximately $12 to $14 million annually, which could potentially decrease progressively over time as the asset depreciates.

Risks Related to Our Indebtedness

Our indebtedness could adversely affect our ability to raise additional capital to fund our operations or pay dividends. It could also expose us to the risk of increased interest rates and limit our ability to react to changes in the economy or our industry as well as impact our cash available for distribution

As of December 31, 2017, we had approximately (i) $5,475.2 million of total indebtedness under various project-level debt arrangements and (ii) $643.1 million of total indebtedness under our corporate arrangements, which include the 2019 Notes and our drawdowns under the Revolving Credit Facility and the Note Issuance Facility. Our substantial debt could have important negative consequences on our financial condition, including:

- increasing our vulnerability to general economic and industry conditions;
- requiring a substantial portion of our cash flow from operations to be dedicated to the payment of principal and interest on our indebtedness, therefore reducing our ability to pay dividends to holders of our shares or to use our cash flow to fund our operations, capital expenditures and future business opportunities;
- limiting our ability to enter into long-term power sales, fuel purchases and swaps which require credit support;
- limiting our ability to fund operations or future acquisitions;
- restricting our ability to make certain distributions with respect to our shares and the ability of our subsidiaries to make certain distributions to us, in light of restricted payment and other financial covenants in our credit facilities and other financing agreements;
- exposing us to the risk of increased interest rates because a portion of some of our borrowings (below 10% as of the date hereof) are at variable rates of interest;
- limiting our ability to obtain additional financing for working capital, including collateral postings, capital expenditures, debt service requirements, acquisitions and general corporate or other purposes; and
- limiting our ability to adjust to changing market conditions and placing us at a competitive disadvantage compared to our competitors who have less debt.

The operating and financial restrictions and covenants in the indenture governing the 2019 Notes, the credit agreement governing the Revolving Credit Facility, and the facility agreement governing the Note Issuance Facility may adversely affect our ability to finance our future operations or capital needs, to engage in other business activities that may be in our interest and to execute our business strategy as we intend to do so.

The indenture governing the 2019 Notes contains covenants that limit certain of our and the guarantors’ activities, including those relating to: incurring additional indebtedness; paying dividends on, redeeming or repurchasing our capital stock; prepaying subordinated indebtedness; making certain investments; imposing certain restrictions on the ability of subsidiaries to pay dividends or other payments; creating certain liens; transferring or selling assets; merging or consolidating with other entities; entering into transactions with affiliates; and engaging in unrelated businesses. Each of the covenants is subject to a number of important exceptions and qualifications. In addition, certain of the covenants listed above will terminate before the 2019 Notes mature if at least two of the specified rating agencies assign the 2019 Notes an investment grade rating in the future and no events of default under the indenture governing the 2019 Notes exist and are continuing. Any covenants that cease to apply to us as a result of achieving investment grade ratings will not be restored, even if the credit ratings assigned to the 2019 Notes later fall below investment grade. The indenture governing the 2019 Notes also contains customary events of default (subject in certain cases to customary grace and cure periods). Generally, if an event of default occurs and is not cured within the time periods specified, the trustee or the holders of at least 25.0% in principal amount of the 2019 Notes then outstanding may declare all of the 2019 Notes to be due and payable immediately.

The Revolving Credit Facility contains covenants that limit certain of our and the guarantors' activities, including those relating to: mergers; consolidations; the ability to incur additional indebtedness; sales, transfers and other dispositions of property and assets; providing new guarantees; investments; granting additional security interests, transactions with affiliates and our ability to pay cash dividends is also subject to certain standard restrictions. Additionally, we are required to comply with (i) a maintenance leverage ratio of our indebtedness at the holding level to our cash available for distribution of 5.00:1.00 from January 1, 2018 and (ii) an interest coverage ratio of cash available for distribution to debt service payments of 2.00:1.00 for the duration of the agreement. The Revolving Credit Facility also contains customary events of default, the ability of the lenders to declare the unpaid principal amount of all outstanding loans, and interest accrued thereon, to be immediately due and payable. In addition, our Revolving Credit Facility includes a cross-default provision related to a default by our project subsidiaries in their financing arrangements, such that a payment default by one or more of our non-recourse subsidiaries representing more than 20.0% of the cash available for distribution distributed in the previous four fiscal quarters could trigger a default under our Revolving Credit Facility.

Additionally, the Note Issuance Facility contains covenants that limit certain of our and the guarantors' activities, including those relating to: mergers; consolidations; the ability to incur additional indebtedness; sales, transfers and other dispositions of property and assets; providing new guarantees; investments; granting additional security interests, transactions with affiliates and our ability to pay cash dividends is also subject to certain standard restrictions. Additionally, we are required to comply with (i) a maintenance leverage ratio of our indebtedness (including that of our subsidiaries) to our cash available for distribution of 5.00:1.00 from January 1, 2017, and of 4.75:1.00 from January 1, 2020, and (ii) a debt service coverage ratio of 2.00:1.00 of cash available for distribution to debt service payments.

If we violate any of these covenants, a default may result, which, if not cured or waived, could result in the acceleration of our debt and could limit our ability to pay dividends.

The agreements governing our project-level financing contain financial and other restrictive covenants that limit our project subsidiaries' ability to make distributions to us or otherwise engage in activities that may be in our long-term best interests. The extent of the restrictions on our subsidiaries' ability to transfer assets to us through loans, advances or cash dividends without the consent of third parties is significant. The project-level financing agreements generally prohibit distributions from the project entities to us unless certain specific conditions are met, including the satisfaction of certain financial ratios. In addition, the project-level financing for some of our assets prohibits distributions until the first principal repayment is made. Our inability to satisfy certain financial covenants may prevent cash distributions by the particular project(s) to us and, our failure to comply with those and other covenants could result in an event of default which, if not cured or waived, may entitle the related lenders to demand repayment or enforce their security interests, which could have a material adverse effect on our business, results of operations, financial condition and cash flows. In addition, failure to comply with such covenants, including covenants under our 2019 Notes, the Revolving Credit Facility and the Note Issuance Facility, may entitle the related noteholders or lenders, as applicable, to demand repayment and accelerate all such indebtedness. If our project-level subsidiaries are unable to make distributions, it would likely have a material adverse effect on our ability to pay dividends to holders of our shares.

Letter of credit facilities or personal guarantees to support project-level contractual obligations generally need to be renewed, at which time we will need to satisfy applicable financial ratios and covenants. If we are unable to renew the letters of credit as expected or replace them with letters of credit under different facilities on favorable terms or at all, we may experience a material adverse effect on our business, financial condition, results of operations and cash flows. Furthermore, such inability may constitute a default under certain project-level financing arrangements, restrict the ability of the project-level subsidiary to make distributions to us and/or reduce the amount of cash available at such subsidiary to make distributions to us.

In addition, our ability to arrange financing, either at the corporate level or at a non-recourse project-level subsidiary, and the costs of such capital, are dependent on numerous factors, including:

- general economic and capital market conditions;
- credit availability from banks and other financial institutions;

- investor confidence in us, our partners: Algonquin, as our largest shareholder upon the completion of the Share Sale, for which all conditions precedent have been satisfied and for which the parties have commenced the process for the transfer of our shares, which we expect to close in the upcoming days, and Abengoa as a shareholder and a supplier;

- final outcome of Abengoa's insolvency proceedings;

- our financial performance and the financial performance of our subsidiaries;

- our level of indebtedness and compliance with covenants in debt agreements;

- maintenance of acceptable project credit ratings or credit quality;

- cash flow; and

- provisions of tax and securities laws that may impact raising capital.

We may not be successful in obtaining additional capital for these or other reasons. Furthermore, we may be unable to refinance or replace project-level financing arrangements or other credit facilities on favorable terms or at all upon the expiration or termination thereof. Our failure, or the failure of any of our projects, to obtain additional capital or enter into new or replacement financing arrangements when due may constitute a default under such existing indebtedness and may have a material adverse effect on our business, financial condition, results of operations and cash flows.

Potential future defaults by our subsidiaries, Abengoa or other persons could adversely affect us

Our project subsidiaries' financing agreements are primarily loan agreements and related documents which, except as noted below, require the loans to be repaid solely from the revenue of the project being financed thereby, and provide that the repayment of the loans (and interest thereon) is secured solely by the shares, physical assets, contracts and cash flow of that project company. This type of financing is usually referred to herein as "project debt." As of December 31, 2017, we had $5,475.2 million of outstanding indebtedness under various project-level debt arrangements.
While the lenders under our project debt do not have direct recourse to us or our subsidiaries (other than the project borrowers under those financings), defaults by the project borrowers under such financings can still have important consequences for us and our subsidiaries, including, without limitation:

- reducing our receipt of dividends, fees, interest payments, loans and other sources of cash, since the project company will typically be prohibited from distributing cash to us and our subsidiaries during the pendency of any default;

- causing us to record a loss in the event the lender forecloses on the assets of the project company; and

- the loss or impairment of investors' and project finance lenders' confidence in us.

If we were to fail to satisfy any of our debt service obligations or to breach any related financial or operating covenants, the applicable lender could declare the full amount of the relevant indebtedness to be immediately due and payable and could foreclose on any assets pledged as collateral.

The financing arrangements of some of our project subsidiaries contained cross-default provisions related to Abengoa, such that debt defaults by Abengoa could trigger defaults under such project financing arrangements. In addition, some of our project financing arrangements contained a change of control provision that would be triggered if Abengoa ceases to own at least 35.0% of Atlantica Yield's shares. During the years 2015, 2016 and 2017, waivers and forbearances have been obtained for most of our project financing agreements from all the parties of these project financing arrangements containing such covenants.

In March 2017, we obtained a waiver in our Kaxu project financing arrangement which waives any potential cross-defaults with Abengoa up to that date, but it does not cover potential future cross-default events.

In the case of Solana and Mojave, a forbearance agreement signed with the DOE in 2016 with respect to these assets allows reductions of Abengoa's ownership of our shares if it results from (i) a sale or other disposition at any time pursuant to and in connection with a subsequent insolvency proceeding by Abengoa, or (ii) capital increases by us. In other events of reduction of ownership by Abengoa below the minimum ownership threshold such as sales of shares by Abengoa, the available DOE remedies will not include debt acceleration, but DOE remedies available could include limitations on distributions to us from Solana and Mojave. In addition, the minimum ownership threshold for Abengoa's ownership of our shares has been reduced from 35.0% to 30.0%. In November 2017, in the context of the agreement reached between Abengoa and Algonquin for the acquisition by Algonquin of 25.0% of our shares and based on the obligations of Abengoa under an EPC contract, we signed a consent in relation to the Solana and Mojave projects which reduces the minimum ownership required by Abengoa in us from 30.0% to 16.0%, subject to certain conditions precedent. In Solana, the EPC guarantee period expired without reaching the expected production. As the EPC supplier, Abengoa agreed to provide certain compensations. As a result, the main conditions precedent included several payments by Abengoa to Solana before December 2017 and February 2018 (subsequently postponed to May 2018), for a total amount of $120 million. Additionally, Abengoa has recognized other obligations to Solana for $6.5 million per half-year over 10 years starting in December 2018. In December 2017, Solana received $42.5 million which was used to repay project finance debt. Solana is expected to receive in March 2018 an additional $77.5 million. From this amount $52.5 million are expected to be used to repay project debt and $25 million are expected to cover other current and potential future Abengoa obligations.

Neither our Revolving Credit Facility nor our Note Issuance Facility include a cross-default provision related to Abengoa. They both include, however, a cross-default provision related to a default by our project subsidiaries in their financing arrangements. Under the Revolving Credit Facility, a payment default by one or more of our non-recourse subsidiaries representing more than 20.0% of the cash available for distribution distributed in the previous four fiscal quarters could trigger a default under our Revolving Credit Facility. In addition, our Note Issuance Facility includes a cross-default provision related to a payment default by (i) us or our subsidiaries, other than our non-recourse subsidiaries, with respect to indebtedness for more than $75 million, or (ii) our non-recourse subsidiaries with respect to indebtedness for more than $100 million.
Any of these events could have a material adverse effect on our financial condition, results of operations or cash flows.

Risks Related to Ownership of our Shares

We may not be able to pay a specific or increasing level of cash dividends to holders of our shares in the future

The amount of our cash available for distribution principally depends upon the amount of cash we generate from our operations, which will fluctuate from quarter to quarter based on, among other things:

- the level and timing of capital expenditures we make;
- the level of our operating and general and administrative expenses;
- seasonal variations in revenues generated by the business;
- operational performance of our assets;
- potential capital expenditure requirements in our assets in the case there were technical problems not covered by the EPC contractor guarantee or by insurance;
- our debt service requirements and other liabilities;

- fluctuations in our working capital needs;

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- our ability to borrow funds;
- restrictions contained in our debt agreements (including our project-level financing);
- changes in our revenues due to delays in collections from our offtakers, legal disputes regarding contact terms or adjustments contemplated in existing regulation or changes in regulation or taxes in the countries in which we operate;
- potential restrictions on payment of dividends arising from cross-default provisions with Abengoa or change of ownership provisions included in certain of our project financing agreements; and
- other business risks affecting our cash levels.

As a result of all these factors, we cannot guarantee that we will have sufficient cash generated from operations to pay a specific or increasing level of cash dividends to holders of our shares. Furthermore, holders of our shares should be aware that the amount of cash available for distribution depends primarily on our cash flow, and is not solely a function of profitability, which is affected by non-cash items. We may incur other expenses or liabilities during a period that could significantly reduce or eliminate our cash available for distribution and, in turn, impair our ability to pay dividends to shareholders during the period. Because we are a holding company, our ability to pay dividends on our shares is limited by restrictions or limitations on the ability of our subsidiaries to pay dividends or make other distributions, such as pursuant to shareholder loans, capital reductions or other means, to us, including restrictions under the terms of the agreements governing project-level financing, the 2019 Notes, the Revolving Credit Facility, the Note Issuance Facility or legal, regulatory or other restrictions or limitations applicable in the various jurisdictions in which we operate, such as exchange controls or similar matters or corporate law limitations, any of which could change from time to time and thereby limit our subsidiaries' ability to pay dividends or make other distributions to us. Our project-level financing agreements generally prohibit distributions to us unless certain specific conditions are met, including the satisfaction of financial ratios.

In 2016, our board of directors decided not to pay a dividend with respect to the first quarter, and declared a reduced dividend in the following quarters, based on the fact that certain of our assets contain cross default provisions and change of ownership provisions with Abengoa. In 2017, with the receipt of most waivers, we progressively increased our dividends. However, we cannot assure you that our board of directors will not take similar measures in upcoming periods.

Our cash available for distribution will likely fluctuate from quarter to quarter, in some cases significantly, due to seasonality. See "Item 4.B—Business Overview—Seasonality." As result, we may reduce the amount of cash we distribute in a particular quarter to establish reserves to fund distributions to shareholders in future periods for which the cash distributions we would otherwise receive from our subsidiary project companies would otherwise be insufficient to fund our quarterly dividend. If we fail to establish sufficient reserves, we may not be able to maintain our quarterly dividend with a respect to a quarter adversely affected wit by seasonality.

Dividends to holders of our shares will be paid at the discretion of our board of directors. Our board of directors may decrease the level of or entirely discontinue payment of dividends. Our board of directors may change our dividend policy at any point in time or modify the dividend for specific quarters following prevailing conditions. For a description of additional restrictions and factors that may affect our ability to pay cash dividends, please see "Item 8.A—Consolidated Statements and Other Financial Information—Dividend Policy."

We are a holding company and our only material assets are our interests in our subsidiaries, upon whom we are dependent for distributions to pay dividends, taxes and other expenses

We are a holding company whose sole material assets consist of our interests in our subsidiaries. We do not have any independent means of generating revenue. We intend to cause our operating subsidiaries to make distributions to us in an amount sufficient to cover our corporate debt services, corporate general and administrative expenses, all applicable taxes payable and dividends, if any, declared by us. To the extent that we need funds for a quarterly cash dividend to holders of our shares or otherwise, and one or more of our operating subsidiaries is restricted from making such distributions under the terms of its financing or other agreements or applicable law and regulations or is otherwise unable to provide such funds, it could materially adversely affect our liquidity and financial condition and limit our ability to pay dividends to shareholders.

We have a limited operating history and as a result there is no assurance we can operate on a profitable basis

We have a limited operating history on which to base an evaluation of our business and prospects. Our prospects must be considered in light of the risks, expenses and difficulties frequently encountered by companies in their early stages of operation. We cannot assure you that we will be successful in addressing the risks we may encounter, and our failure to do so could have a material adverse effect on our business, financial condition, results of operations and cash flows.

Market interest rates may have an effect on the value of our shares

One of the factors that will influence the price of our shares will be the effective dividend yield of our shares (i.e., the yield as a percentage of the then-market price of our shares) relative to market interest rates. A continued increase in market interest rates, which are still at relatively low levels compared to historical rates, may lead prospective purchasers of our shares to expect a higher dividend yield. In the United States, interest rates, and expectations of still higher interest rates, have increased over the past year in the markets. During the first two months of 2018, equities in the United States have experienced a downturn which has also affected utilities and the yieldco sector, partially due to expectations of interest rates increases. The low price of our shares might make our dividend per share growth more difficult, since acquisitions financed with equity could be less accretive. Our inability to increase our dividend as a result of an increase in borrowing costs, insufficient cash available for distribution or otherwise could result in selling pressure on, and a decrease in, the market price of our shares as investors seek alternative investments with higher yield.

Market volatility may affect the price of our shares and the value of your investment

The market for securities issued by issuers such as us is influenced by economic and market conditions and, to varying degrees, market conditions, interest rates, currency exchange rates and inflation rates in other countries. There can be no assurance that events in the United States, Latin America, Europe, Africa or elsewhere will not cause market volatility or that such volatility will not adversely affect the price of the shares or that economic and market conditions will not have any other adverse effect. Fluctuations in interest rates may give rise to arbitrage opportunities based upon changes in the relative value of the shares. Any trading by arbitrageurs could, in turn, affect the trading price of the shares. In the past there has been correlation between the price of our shares, the price of oil and the price of shares of master limited partnerships, or MLPs, and a decline in the price of oil or MLP shares could cause a decline in the price of our shares. The price of our shares can also be affected by our peers' share price. Securities markets in general may experience extreme volatility that is unrelated to the operating performance of particular companies. Any broad market fluctuations may adversely affect the trading of our shares.

In addition, the market price of our shares may fluctuate in the event of negative developments at Abengoa, Algonquin, the termination of the AAGES, Algonquin or Abengoa ROFO Agreements, uncertainty on the sale process of the remaining 16.47% stake of Abengoa in us, or additions or departures of our key personnel, changes in market valuations of similar companies, Algonquin or Abengoa and/or speculation in the press or investment community regarding us, Algonquin or Abengoa.

You may experience dilution of your ownership interest due to the future issuance of additional shares

In order to finance the growth of our business through future acquisitions, we may require additional funds from further equity or debt financings, including tax equity financing transactions or sales of preferred shares or convertible debt, to complete future acquisitions, expansions and capital expenditures and pay the general and administrative costs of our business. In the future, we may issue our previously authorized and unissued securities, resulting in the dilution of the ownership interests of purchasers of our shares offered hereby. The potential issuance of additional shares or preferred stock or convertible debt may create downward pressure on the trading price of our shares. We may also issue additional shares or other securities that are convertible into or exercisable for our shares in future public offerings or private placements for capital-raising purposes or for other business purposes, potentially at an offering price, conversion price or exercise price that is below the offering price for our shares in any of our previous offering.

If securities or industry analysts do not publish or cease to publish research or reports about us, our business or our market, or if they change their recommendations regarding our shares adversely, the price and trading volume of our shares could decline

The trading market for our shares will be influenced by the research and reports that industry or securities analysts may publish about us, Algonquin, Abengoa, our business, our market or our competitors. If any of the analysts who may cover us change their recommendations regarding our shares adversely, or provide more favorable relative recommendations about our competitors, the price of our shares would likely decline. If any analyst who may cover us were to cease coverage of our company or fail to regularly publish reports on us, we could lose visibility in the financial markets, which in turn could cause the price or trading volume of our shares to decline.

Future sales of our shares by Algonquin, Abengoa or its lenders may cause the price of our shares to fall

The market price of our shares could decline as a result of future sales by Algonquin or Abengoa of its shares in the market, or the perception that these sales could occur. Upon the completion of the Share Sale, Algonquin will own 25.0% or our ordinary shares, and Abengoa will own 16.47% of our ordinary shares. The shares owned by Abengoa are pledged to financial institutions as collateral for borrowings under financing arrangements.

Abengoa has communicated that it intends to sell its remaining 16.47% stake in us over the upcoming months in a private transaction, subject to approval by the DOE. Algonquin has an option to purchase this remaining stake until March 2018, according to public information. If Abengoa defaults on any of these financing arrangements, such lenders may foreclose on the shares and sell the shares in the market. Future sales of substantial amounts of the shares and/or equity-related securities in the public market, or the perception that such sales could occur, could adversely affect prevailing trading prices of the shares and could impair our ability to raise capital through future offerings of equity or equity-related securities. The price of the shares could be depressed by investors' anticipation of the potential sale in the market of substantial additional amounts of shares. Disposals of shares could increase the number of shares being offered for sale in the market and depress the trading price of our shares.

As a "foreign private issuer" in the United States, we are exempt from certain rules under the U.S. securities laws and are permitted to file less information with the SEC than U.S. companies

As a "foreign private issuer," we are exempt from certain rules under the Exchange Act that impose certain disclosure obligations and procedural requirements for proxy solicitations under Section 14 of the Exchange Act. In addition, our officers, directors and principal shareholders are exempt from the reporting and "short-swing" profit recovery provisions of Section 16 of the Exchange Act and the rules under the Exchange Act with respect to their purchases and sales of our shares. Moreover, we are not required to file periodic reports and financial statements with the SEC as frequently or as promptly as U.S. companies whose securities are registered under the Exchange Act. In addition, we are not required to comply with Regulation FD, which restricts the selective disclosure of material information. If we were to lose our "foreign private issuer" status, we would no longer be exempt from certain provisions of the U.S. securities laws we would be required to commence reporting on forms required of U.S. companies, and we could incur increased compliance and other costs, among other consequences.

Judgments of U.S. courts may not be enforceable against us

Judgments of U.S. courts, including those predicated on the civil liability provisions of the federal securities laws of the United States, may not be enforceable in courts in the United Kingdom or other countries in which we operate. As a result, our shareholders who obtain a judgment against us in the United States may not be able to require us to pay the amount of the judgment.

There are limitations on enforceability of civil liabilities under U.S. federal securities laws

We are incorporated under the laws of England and Wales. Most of our officers and directors reside outside of the United States. In addition, a portion of our assets and the majority of the assets of our directors and officers are located outside the United States. As a result, it may be difficult or impossible to serve legal process on persons located outside the United States and to force them to appear in a U.S. court. It may also be difficult or impossible to enforce a judgment of a U.S. court against persons outside the United States, or to enforce a judgment of a foreign court against such persons in the United States. We believe that there may be doubt as to the enforceability against persons in England and Wales and in Spain, whether in original actions or in actions for the enforcement of judgments of U.S. courts, of civil liabilities predicated solely upon the laws of the United States, including its federal securities laws. Because we are a foreign private issuer, our directors and officers will not be subject to rules under the Exchange Act that under certain circumstances would require directors and officers to forfeit to us any "short-swing" profits realized from purchases and sales, as determined under the Exchange Act and the rules thereunder, of our equity securities. In addition, punitive damages in actions brought in the United States or elsewhere may be unenforceable in England and Wales and in Spain.

Shareholders in certain jurisdictions may not be able to exercise their pre-emptive rights if we increase our share capital

Under our articles of association, holders of our shares generally have the right to subscribe and pay for a sufficient number of our shares to maintain their relative ownership percentages prior to the issuance of any new shares in exchange for cash consideration. Holders of shares in certain jurisdictions may not be able to exercise their pre-emptive rights unless securities laws have been complied with in such jurisdictions with respect to such rights and the related shares, or an exemption from the requirements of the securities laws of these jurisdictions is available. To the extent that such shareholders are not able to exercise their pre-emptive rights, the pre-emptive rights would lapse, and the proportional interests of such holders would be reduced.

In addition, under the Shareholders Agreement that will become effective upon completion of the Share Sale, for which all conditions precedent have been satisfied and for which the parties have commenced the process for the transfer of our shares, which we expect to close in the upcoming days, AAGES or Algonquin or both of them may subscribe in cash for (i) up to 100.0% of our ordinary shares if the purpose of the issuance is to fund our acquisition of assets under the AAGES or Algonquin ROFO Agreement; and (ii) up to 66.0% of our ordinary shares if the purpose of the issuance is to fund our acquisition of assets under the Abengoa ROFO Agreement. If we issue ordinary shares for any other purpose, AAGES or Algonquin may subscribe in cash for our ordinary shares in a pro rata amount of such AAGES' or Algonquin's aggregate holding of voting rights in us.

The rights of our shareholders may differ from the rights typically offered to shareholders of a U.S. corporation organized in Delaware

We are incorporated under English law. The rights of holders of our shares are governed by English law, including the provisions of the UK Companies Act 2006, and by our articles of association. These rights differ in certain respects from the rights of shareholders in typical U.S. corporations organized in Delaware. The principal differences are set forth in "Item 10.B—Memorandum and Articles of Association."

Provisions in the UK City Code on Takeovers and Mergers may have anti-takeover effects that could discourage an acquisition of us by others, even if an acquisition would be beneficial to our shareholders

The UK City Code on Takeovers and Mergers, or the Takeover Code, applies, among other things, to an offer for a public company whose registered office is in the United Kingdom and whose securities are not admitted to trading on a regulated market in the United Kingdom if the company is considered by the Panel on Takeovers and Mergers, or the Takeover Panel, to have its place of central management and control in the United Kingdom. This is known as the "residency test." The test for central management and control under the Takeover Code is different from that used by the UK tax authorities. Under the Takeover Code, the Takeover Panel will determine whether we have our place of central management and control in the United Kingdom by looking at various factors, including the structure of our board of directors, the functions of the directors and where they are resident.

If at the time of a takeover offer the Takeover Panel determines that we have our place of central management and control in the United Kingdom, we would be subject to a number of rules and restrictions, including but not limited to the following: (1) our ability to enter into deal protection arrangements with a bidder would be extremely limited; (2) we may not, without the approval of our shareholders, be able to perform certain actions that could have the effect of frustrating an offer, such as issuing shares or carrying out acquisitions or disposals; and (3) we would be obliged to provide equality of information to all bona fide competing bidders.

Risks Related to Taxation

Changes in our tax position can significantly affect our reported earnings and cash flows

Changes in corporate tax rates and/or other relevant tax laws in the United Kingdom, the United States or the other countries in which our assets are located could have a material impact on our future tax rate and/or our required tax payments. Although we consider our tax provision to be adequate, the final determination of our tax liability could be different from the forecasted amount, which could have potential adverse effects on our financial condition and cash flows. In relation to the United Kingdom Controlled Foreign Company regime, or the U.K. CFC rules, we have good arguments to consider that the foreign entities held under Atlantica Yield would not be subject to the U.K. CFC rules. Changes to the U.K. CFC rules or adverse interpretations of them, could have effects on the future tax rate and/or required tax payments in Atlantica Yield. With respect to some of our projects, we must meet defined requirements to apply favorable tax treatment, such as lower tax rates or exemptions. We intend to meet these requirements in order to benefit from the favorable tax treatment; however, there can be no assurance that we will be able to comply with all of the necessary requirements in the future, or the requirements could change or be interpreted in another manner, which could give rise to a greater tax liability and which could have an adverse effect on our results of operations and cash flows.

Our future tax liability may be greater than expected if we do not utilize net operating losses or net operating loss carryforwards sufficient to offset our taxable income

We expect to generate net operating losses and net operating loss carryforwards (collectively, "NOLs") that we can use to offset future taxable income. Based on our current portfolio of assets, which include renewable assets that benefit from an accelerated tax depreciation schedule, and subject to potential tax audits, which may result in income, sales, use or other tax obligations, we do not expect to pay significant taxes for a period of approximately 10 years, with the exception of ACT in Mexico, where we do not expect to pay significant income taxes until the fifth or sixth year after our IPO (i.e. until 2019 or 2020) once we use existing NOLs.

While we expect these NOLs will be available to us as a future benefit, in the event that they are not generated as expected, or are successfully challenged by the local tax authorities, such as the U.S. Internal Revenue Service, or the IRS, or Her Majesty's Revenue and Customs among others, by way of a tax audit or otherwise, or are subject to future limitations as discussed below, our ability to realize these benefits may be limited. A reduction in our expected NOLs, a limitation on our ability to use such NOLs or the occurrence of future tax audits may result in a material increase in our estimated future income tax liability and may negatively impact our results of operations and liquidity.

Our ability to use U.S. NOLs to offset future income may be limited

We have generated significant U.S. NOLs. We generally are able to carry U.S. NOLs forward to reduce our tax liability in future years. Federal U.S. NOLs generated on or before December 31, 2017 can generally be carried back two years and carried forward for up to twenty years and can be applied to offset 100% of taxable income in such years. Under the TCJA, however, federal U.S. NOLs incurred in 2018 and in future years may be carried forward indefinitely but may not be carried back and the deductibility of such federal U.S. NOLs is limited to 80% of taxable income in such years. It is uncertain how various states will respond to the newly enacted federal tax law.

In addition, our ability to use U.S. NOLs generated is subject to the rules of Sections 382 of the IRC. This section generally restricts the use of U.S. NOLs if we were to experience an "ownership change" as defined under Section 382 of the IRC, and similar state rules. In general, an "ownership change" would occur if our "5-percent shareholders," as defined under Section 382 of the IRC, collectively increased their ownership in us by more than 50 percentage points over a rolling three-year period. A corporation that experiences an ownership change will generally be subject to an annual limitation on the use of its pre-ownership change U.S. NOLs equal to the equity value of the corporation immediately before the ownership change, multiplied by the long-term tax-exempt rate for the month in which the ownership change occurs, and increased by a certain portion of any "built-in-gains."

The Abengoa restructuring has caused a change of ownership under Section 382 of the IRC, which has limited in part our ability to use net operating loss carryforwards. See "Item 5.A—Operating Results—Results of Operations—Factors affecting the comparability of our results of operations—Change of ownership under Section 382 of the IRC." The potential total or partial sale by Abengoa of its stake in us may have caused or may cause another change of ownership, which may limit further our ability to use net operating loss carryforwards in the United States. Future sales by our largest shareholders, future equity issuances and in general the activity of our direct or indirect shareholders may limit further our ability to use net operating loss carryforwards in the United States, which could have a potential adverse effect on cash flows from U.S. projects expected in the future.
In addition, because we have recorded tax credits for the U.S. tax losses carryforwards in the past, a limit to our ability to use net operating loss carryforwards in the United States could result in writing off tax credits, which could cause a substantial non-cash Income tax expense in our financial statements.

U.S. federal income tax reform could adversely affect us

On December 22, 2017, the United States enacted new tax legislation, the TCJA, which provides for substantial changes to the U.S. taxation of businesses and individuals. The TCJA, among other things, significantly reduces the U.S. federal tax rate applicable to corporations, imposes significant additional limitations on the deductibility of interest, temporarily allows for the expensing of certain capital expenditures, limits the deduction for NOLs to 80% of current year taxable income and eliminates NOL carrybacks, in each case, for losses arising in taxable years beginning after December 31, 2017 (though any such NOLs may be carried forward indefinitely). We do not expect tax reform to have a material impact on our projection of minimal cash taxes or on our net operating losses. Our net deferred tax assets and liabilities have been revalued at the newly enacted U.S. corporate rate, and the impact has been recognized in our tax expense for 2017. See "Item 5.A—Operating Results—Results of Operations—Factors affecting the comparability of our results of operations—U.S. Tax Reform." Additionally, while the ITC and the PTC available for renewable energy investments in the United States were left unchanged, the lower corporate tax rate and the new base erosion anti-abuse tax (intended to prevent international groups from 'earnings stripping' through certain payments to foreign affiliates) may impact the cost and availability of tax equity financing, which could have a negative effect on our growth prospects in the United States. We continue to examine the impact this tax reform legislation may have on our business. The impact of this tax reform on stockholders is uncertain and could be adverse. We urge prospective investors to consult with their legal and tax advisors with respect to such legislation and the potential tax consequences of investing in our shares.

Distributions to U.S. Holders of our shares may be fully taxable as dividends

It is difficult to predict whether or to what extent we will generate earnings or profits as computed for U.S. federal income tax purposes in any given tax year. If we make distributions on the shares from current or accumulated earnings and profits as computed for U.S. federal income tax purposes, such distributions generally will be taxable to U.S. Holders of our shares as ordinary dividend income for U.S. federal income tax purposes. Under current law, if certain requirements are met, such dividends would be eligible for the lower tax rates applicable to qualified dividend income of certain non-corporate U.S. Holders. While we expect that a portion of our distributions to U.S. Holders of our shares may exceed our current and accumulated earnings and profits as computed for U.S. federal income tax purposes, and therefore may constitute a non-taxable return of capital to the extent of a U.S. Holder's basis in our shares, no assurance can be given that this will occur. We intend to calculate our earnings and profits annually in accordance with U.S. federal income tax principles. See "Item 10.E—Taxation—Material U.S. Federal Income Tax Considerations."

If we are a passive foreign investment company for U.S. federal income tax purposes for any taxable year, U.S. Holders of our shares could be subject to adverse U.S. federal income tax consequences

If we were a "passive foreign investment company" within the meaning of Section 1297 of the IRC (a "PFIC") for any taxable year during which a U.S. Holder held our shares, certain adverse U.S. federal income tax consequences may apply to the U.S. Holder. We do not believe that we were a PFIC for our 2017 taxable year and do not expect to be a PFIC for U.S. federal income tax purposes for the current taxable year or in the foreseeable future. However, PFIC status depends on the composition of a company's income and assets and the fair market value of its assets (including, among others, less than 25.0% owned equity investments) from time to time, as well as on the application of complex statutory and regulatory rules that are subject to potentially varying or changing interpretations. Accordingly, there can be no assurance that we will not be considered a PFIC for any taxable year.

If we were a PFIC, U.S. Holders of our shares may be subject to adverse U.S. federal income tax consequences, such as taxation at the highest marginal ordinary income tax rates on capital gains and on certain actual or deemed distributions, interest charges on certain taxes treated as deferred, and additional reporting requirements. See "Item 10.E—Taxation—Material U.S. Federal Income Tax Considerations—Passive foreign investment company rules."

Changes in tax regimes may affect us adversely

We have assets in different jurisdictions, which are subject to different tax regimes. Changes in tax regimes such as the reduction or elimination of tax benefits, or the reduction of tax rates overall in markets where we operate could adversely affect the market for investments in our projects by third parties. A reduction in corporate tax rates could make investments in renewable projects less attractive to potential tax equity investors, in which case we may not be able to obtain third-party financing on terms as beneficial as in the past, or at all, which could limit our ability to grow our business. Limitations on the deductibility of interest expense could reduce our ability to deduct the interest we pay on our debt. These and other potential changes in tax regulations could have a material adverse effect on our results and cash flows.

ITEM 4. INFORMATION ON THE COMPANY

A. History and Development of the Company

We were incorporated in England and Wales as a private limited company on December 17, 2013 under the name "Abengoa Yield Limited." On March 19, 2014, we were re-registered as a public limited company, under the name "Abengoa Yield plc." On January 7, 2016, we changed our corporate brand to Atlantica Yield. At our annual shareholders meeting held in May 2016, we changed our legal name to Atlantica Yield plc.

The address of our principal executive offices is Great West House, GW1, 17th floor, Great West Road, Brentford, United Kingdom TW8 9DF, and our phone number is +44 203 499 0465.

We are a total return company that owns, manages, and acquires renewable energy, efficient natural gas (previously named "conventional") power, electric transmission lines and water assets, focused on North America (the United States and Mexico), South America (Peru, Chile and Uruguay) and EMEA (Spain, Algeria and South Africa). We intend to expand maintaining North America, South America and Europe as our core geographies.

On June 18, 2014, we completed our IPO and listed our shares on the NASDAQ Global Select Market under the symbol "ABY." On November 14, 2017, the ticker symbol was changed to "AY."

Prior to the consummation of our IPO, Abengoa transferred to us ten assets representing an initial portfolio comprising 710 MW of renewable energy generation, 300 MW of efficient natural gas (previously named "conventional") power generation and 1,018 miles of electric transmission lines and an exchangeable preferred equity investment in ACBH. The assets in the initial portfolio consisted of:

- Renewable energy assets in the initial public offering consisted of (i) two solar power plants in the United States, Solana and Mojave, each with a gross capacity of 280 MW; (ii) one on-shore wind farm in Uruguay, Palmatir, with a gross capacity of 50 MW and (iii) a solar power complex in Spain, Solaben 2/3, with a gross capacity of 100 MW.

- Efficient natural gas power assets consisting of ACT Energy Mexico, or ACT, a 300 MW cogeneration plant in Mexico.

- Electric transmission lines consisting of (i) two lines in Peru, ATN and ATS, spanning a total of 931 miles; and (ii) three lines in Chile, Quadra 1, Quadra 2, and Palmucho, spanning a total of 87 miles.

Upon our IPO, we signed an exclusive agreement with Abengoa, which we refer to as the Abengoa ROFO Agreement, which provides us with a right of first offer on any proposed sale, transfer or other disposition of any of Abengoa's contracted renewable energy, efficient natural gas power, electric transmission or water assets in operation and located in the United States, Canada, Mexico, Chile, Peru, Uruguay, Brazil, Colombia and the European Union, as well as four assets in selected countries in Africa, the Middle East and Asia.

On November 1, 2017, Algonquin agreed to acquire 25.0% of our shares from Abengoa at a price of $24.25 per share, and upon completion of the share sale, will become our largest shareholder. All conditions precedent have been satisfied and the parties have commenced the process for the transfer of our shares, which we expect to close in the upcoming days. In addition, Algonquin and Abengoa have created a joint venture, AAGES, to jointly invest in the development and construction of clean energy and water infrastructure contracted assets. On March 5, 2018 we also entered into a ROFO agreement with AAGES, which provides us with a right of first offer on any proposed sale, transfer or other disposition of AAGES ROFO Assets. Some of the assets currently under construction by Abengoa may be transferred to AAGES and our ROFO agreement with AAGES will include these assets. We also have entered into a ROFO agreement with Algonquin covering certain of their non-U.S. and non-Canadian assets.

Acquisitions

On February 3, 2015, we completed the acquisition of a 25.5% stake in Honaine and a 34.2% stake in Skikda, two desalination plants in Algeria with an aggregate capacity of 10.5 M ft3 per day. On February 23, 2015, we completed the acquisition of a 29.6% stake in Helioenergy 1/2, a solar power asset in Spain with a capacity of 100 MW.

On May 13, 2015, we completed the acquisition of Helios 1/2, a 100 MW solar complex located in Spain. On May 14, 2015, we completed the acquisition of Solnova 1/3/4, a 150 MW solar complex located in Spain. On May 25, 2015, we completed the acquisition of the remaining 70.4% stake in Helioenergy 1/2, a 100 MW solar complex in Spain. On July 30, 2015, we completed the acquisition of Kaxu, a 100 MW solar plant in South Africa.

On June 25, 2015, we completed the acquisition of ATN2, an 81-mile transmission line in Peru from Abengoa and Sigma, a third-party financial investor in the project. On September 30, 2015, we completed the acquisition of Solaben 1/6, a 100 MW solar complex in Spain. On January 7, 2016, we completed the acquisition of a 13% stake in Solacor 1/2, a 100 MW solar complex where we already owned a 74.0% stake.

On August 3, 2016, we completed the acquisition of an 80.0% stake in Seville PV, a 1MW PV plant located next to Solnova 1/3/4.

On February 28, 2017, we completed the acquisition of a 12.5% interest in a 114-mile transmission line in the U.S. from Abengoa at cost. We expect our total investment to be up to $10 million in the coming three years, including the initial amount invested at cost.

On February 28, 2018, we completed the acquisition of a 4 MW mini-hydroelectric power plant in Peru for $9 million. The plant reached COD in 2012. It has a fixed-price concession agreement denominated in U.S. dollars with the Ministry of Energy of Peru and the price is adjusted annually in accordance with the U.S. Consumer Price Index. We financed the acquisition with available cash on hand.

Our largest shareholders Algonquin and Abengoa

When we closed our initial public offering, Abengoa had a 64.28% interest in us. Following several divestitures, since the end of 2015 Abengoa has beneficially owned 41,557,663 of our shares (a 41.47% interest) of which 41,530,843 shares were pledged under the secured New Money 1 Tradable Notes.

In 2015, Abengoa filed a communication pursuant to article 5 bis of the Spanish Insolvency Law 22/2003 with the Mercantile Court of Seville nº 2. On November 8, 2016, the Judge of the Mercantile Court of Seville declared judicial approval of Abengoa's restructuring agreement, extending the terms of the agreement to those creditors who had not approved the restructuring agreement. On February 3, 2017, Abengoa announced it obtained approval from creditors representing 94% of its financial debt after a supplemental accession period. On March 31, 2017, Abengoa announced the completion of its financial restructuring.

On November 1, 2017, Algonquin announced that it had reached an agreement with Abengoa to acquire 25.0% of our shares from Abengoa. Upon completion of the Share Sale, Algonquin will acquire a 25.0% interest in our shares from Abengoa in a private transaction with an option to acquire the remaining 16.47% held by Abengoa prior to March 31, 2018, according to public information. All conditions precedent for the Share Sale have been satisfied and the parties have commenced the process for the transfer of our shares, which we expect to close in the upcoming days. Abengoa has publicly stated that it intends to sell its remaining 16.47% stake in us over the upcoming months in a private transaction, subject to approval by the DOE, should Algonquin not exercise its option. As of the date of the most recent public information, Abengoa owns 41,557,663 shares of us, (41.47%) which are entirely pledged.

In the context of the Algonquin transaction, we signed the Shareholders Agreement with Algonquin, which will become effective upon completion of the Share Sale, which limits Algonquin's ownership in us to a maximum of 41.47% of our outstanding shares (with a certain exception where such ownership may be temporarily increased up to 46%) and limits the number of directors they can appoint to a maximum of 50% less one (if the resulting number is not a whole number, it shall be rounded up to the next whole number). In addition, Algonquin has agreed to provide, subject to board approval, incremental equity investment of up to $100 million through the subscription of our ordinary shares for the acquisition of new assets during 2018 and 2019 and has been granted certain preferred rights when participating in further equity issuances with the possibility of increasing Algonquin's ownership in us up to 41.47% (and up to 46% in certain cases). Additionally, we have agreed to maintain a target payout ratio of 80%. We agreed with Algonquin to periodically discuss the potential acquisition of assets from Algonquin pursuant to the Algonquin ROFO agreement. See "Item 7.B Related Party Transactions."

We have also signed a ROFO agreement with AAGES, the joint venture created between Algonquin and Abengoa to invest in the development and construction of clean energy and water infrastructure contracted assets. The AAGES ROFO Agreement, which will become effective upon completion of the Share Sale, provides us with a right of first offer on any proposed sale, transfer or other disposition of AAGES ROFO Assets. Some of the assets currently under construction by Abengoa may be transferred to AAGES and the AAGES ROFO agreement will include such assets within its scope. Additionally, we have entered into a ROFO agreement with Algonquin, which will become effective upon completion of the Share Sale, pursuant to which Algonquin has agreed to periodically discuss the possibility of the sale to us of interests in certain assets owned by Algonquin in Canada and the United States and which provides us with a right of first offer on any proposed sale, transfer or other disposition of Algonquin's assets located outside of the United States and Canada, which are developed under expected long-term revenue agreements or concession agreements. See "Item 7.B—Related Party Transactions."

B. Business Overview

Overview

We are a total return company that owns, manages, and acquires renewable energy, efficient natural gas (previously named “conventional”) power, electric transmission lines and water assets, focused on North America (the United States and Mexico), South America (Peru, Chile and Uruguay) and EMEA (Spain, Algeria and South Africa). We intend to expand, maintaining North America, South America and Europe as our core geographies.

As of the date of this annual report, we own or have interests in 22 assets, comprising 1,446 MW of renewable energy generation, 300 MW of efficient natural gas power generation, 10.5 M ft3 per day of water desalination and 1,099 miles of electric transmission lines. All of our assets have contracted revenues (regulated revenues in the case of our Spanish assets) with low-risk off-takers and collectively have a weighted average remaining contract life of approximately 19 years as of December 31, 2017. Most of the assets we own have project-finance agreements in place.

We intend to take advantage of favorable trends in the power generation and electric transmission sectors globally, including energy scarcity and a focus on the reduction of carbon emissions. To that end, we believe that our cash flow profile, coupled with our scale, diversity and low-cost business model, offers us a lower cost of capital than that of a traditional engineering and construction company or independent power producer and provides us with a significant competitive advantage with which to execute our growth strategy.

We are focused on high-quality, newly-constructed and long-life facilities with creditworthy counterparties that we expect will produce stable, long-term cash flows. We will seek to grow our cash available for distribution and our dividend to shareholders through organic growth and by acquiring new contracted assets from AAGES, Abengoa, third parties and potential new future partners.

We have in place an exclusive agreement with Abengoa, which we refer to as the Abengoa ROFO Agreement, which provides us with a right of first offer on any proposed sale, transfer or other disposition of any of Abengoa’s contracted renewable energy, efficient natural gas power, electric transmission or water assets in operation and located in the United States, Canada, Mexico, Chile, Peru, Uruguay, Brazil, Colombia and the European Union, as well as four assets in selected countries in Africa, the Middle East and Asia. See “Item 4.B—Business Overview—Our Growth Strategy” and “Item 7.B—Related Party Transactions—Abengoa Right of First Offer.”

In addition, on March 5, 2018 we entered into a ROFO agreement with AAGES, which we refer to as the AAGES ROFO Agreement, that will become effective upon completion of the Share Sale, for which all conditions precedent have been satisfied and for which the parties have commenced the process for the transfer of our shares, which we expect to close in the upcoming days, AAGES is the joint venture formed by Algonquin and Abengoa to develop and invest renewable energy and water assets. The AAGES ROFO Agreement provides us with a right of first offer on any proposed sale, transfer or other disposition of AAGES’ ROFO Assets. See “Item 4.B—Business Overview—Our Growth Strategy” and “Item 7.B—Related Party Transactions—Right of First Offer.”

Additionally, we plan to sign similar agreements or enter into partnerships with other developers or asset owners to acquire assets in operation. We may also invest directly or through investment vehicles with partners in assets under development or construction, ensuring that such investments are always a small part of our total investments. Finally, we also expect to acquire assets from third parties leveraging the local presence and network we have in the geographies and sectors in which we operate.

With this business model, our objective is to pay a consistent and growing cash dividend to shareholders that is sustainable on a long-term basis. We expect to distribute a significant percentage of our cash available for distribution as cash dividends and we will seek to increase such cash dividends over time through organic growth and as we acquire assets with characteristics similar to those in our current portfolio. Pursuant to our cash dividend policy, we intend to pay a cash dividend each quarter to holders of our shares.

Based on the acquisition opportunities available to us, we believe that we will have the opportunity to grow our cash available for distribution in a manner that would allow us to increase our cash dividends per share over time. Prospective investors should read “Item 5.B—Liquidity and Capital Resources—Cash dividends to investors” and “Item 3.D—Risk Factors,” including the risks and uncertainties related to our forecasted results, acquisition opportunities and growth plan, in their entirety.

Purpose of Atlantica Yield

We intend to create value for our shareholders by seeking to (i) achieve recurrent and growing dividends to investors valuing long-term contracted assets and (ii) grow our cash available for distribution and our cash dividends paid to shareholders by acquiring new contracted assets from AAGES, Abengoa, third parties and potential new future partners.

Current Operations

We own a diversified portfolio of contracted assets across the renewable energy, efficient natural gas (previously named “conventional”) power, electric transmission line and water sectors in North America (the United States and Mexico), South America (Peru, Chile and Uruguay) and EMEA (Spain, Algeria and South Africa). We intend to expand, maintaining North America, South America and Europe as our core geographies. Our portfolio consists of 14 renewable energy assets, a natural gas-fired cogeneration facility, several electric transmission lines and minority stakes in two water desalination plants, all of which are fully operational. All of our assets have contracted revenues (regulated revenues in the case of our Spanish assets) with low-risk offtakers and collectively have a weighted average remaining contract life of approximately 19 years as of December 31, 2017. We expect that the majority of our cash available for distribution over the next three years will be in U.S. dollars, indexed to the U.S. dollar or in euros. We intend to maintain a ratio of over 80% of our cash available for distribution denominated in U.S. dollars or euros and to hedge the euros for the upcoming 24 months on a rolling basis strategy. Approximately 93% of our project-level debt is hedged against changes in interest rates through an underlying fixed rate on the debt instrument or through interest rate swaps, caps or similar hedging instruments.

The following table provides an overview of our current assets:

Assets	Type	Ownership	Location	Currency(1)	Capacity (Gross)	Offtaker	Counterparty Credit Rating(2)	COD	Contract Years Left
Solana	Renewable (Solar)	100% Class B(3)	Arizona (USA)	USD	280 MW	APS	A-/A3/A-	4Q 2013	26
Mojave	Renewable (Solar)	100%	California (USA)	USD	280 MW	PG&E	A-/A3/A-	4Q 2014	22
Solaben 2/3(4)	Renewable (Solar)	70%(5)	Spain	EUR	2x50 MW	Wholesale market/Spanish Electric System	BBB+/Baa2/A-	3Q 2012 & 2Q 2012	20 / 19
Solacor 1/2(6)	Renewable (Solar)	87%(7)	Spain	EUR	2x50 MW	Wholesale market/Spanish Electric System	BBB+/Baa2/A-	1Q 2012 & 1Q 2012	19 / 19
PS10/20(8)	Renewable (Solar)	100%	Spain	EUR	31 MW	Wholesale market/Spanish Electric System	BBB+/Baa2/A-	1Q 2007 & 2Q 2009	14 / 16
Helioenergy 1/2(9)	Renewable (Solar)	100%	Spain	EUR	2x50 MW	Wholesale market/Spanish Electric System	BBB+/Baa2/A-	3Q 2011 & 4Q 2011	19 / 19
Helios 1/2(10)	Renewable (Solar)	100%	Spain	EUR	2x50 MW	Wholesale market/Spanish Electric System	BBB+/Baa2/A-	2Q 2012 & 3Q2012	20 / 20
Solnova 1/3/4(11)	Renewable (Solar)	100%	Spain	EUR	3x50 MW	Wholesale market/Spanish Electric System	BBB+/Baa2/A-	2Q 2010 & 2Q 2010 & 3Q 2010	17 / 17 / 18
Solaben 1/6(12)	Renewable (Solar)	100%	Spain	EUR	2x50 MW	Wholesale market/Spanish Electric System	BBB+/Baa2/A-	3Q 2013	21 / 21
Seville PV	Renewable (Solar)	80%(13)	Spain	EUR	1 MW	Wholesale market/Spanish Electric System	BBB+/Baa2/A-	3Q 2006	18
Kaxu	Renewable (Solar)	51%(14)	South Africa	ZAR	100 MW	Eskom	BB/Baa3/ BB+(15)	1Q 2015	17
Palmatir	Renewable (Wind)	100%	Uruguay	USD	50 MW	Uruguay	BBB/Baa2/ BBB-(16)	2Q 2014	16
Cadonal	Renewable (Wind)	100%	Uruguay	USD	50 MW	Uruguay	BBB/Baa2/ BBB-(16)	4Q 2014	17
Mini-hydro Peru	Renewable (Hydro)	100%	Peru	USD	4 MW	Peru	BBB+/A3/ BBB+	2Q 2012	15
ACT	Efficient Natural Gas Power(19)	100%	Mexico	USD	300 MW	Pemex	BBB+/A3/ BBB+	2Q 2013	15
ATN	Transmission Line	100%	Peru	USD	362 miles	Peru	BBB+/A3/ BBB+	1Q 2011	23
ATS	Transmission Line	100%	Peru	USD	569 miles	Peru	BBB+/A3/ BBB+	1Q 2014	26
ATN2	Transmission Line	100%	Peru	USD	81 miles	Minera Las Bambas	Not rated	2Q 2015	15
Quadra 1/2	Transmission Line	100%	Chile	USD	49 miles/32 miles	Sierra Gorda	Not rated	2Q 2014/ 1Q 2014	17/17
Palmucho	Transmission Line	100%	Chile	USD	6 miles	Enel Generacion Chile	BBB+/Baa2/ BBB+	4Q 2007	20
Honaine	Water	25.5%(17)	Algeria	USD	7 M ft3/day	Sonatrach	Not rated	3Q 2012	20
Skikda	Water	34.2%(18)	Algeria	USD	3.5 M ft3/day	Sonatrach	Not rated	1Q 2009	16

Notes:—

(1) Certain contracts denominated in U.S. dollars are payable in local currency.
(2) Reflects the counterparty's issuer credit ratings issued by Standard & Poor's Ratings Services, or S&P, Moody's Investors Service Inc., or Moody's, and Fitch Ratings Ltd, or Fitch.
(3) On September 30, 2013, Liberty agreed to invest $300 million in Class A shares of Arizona Solar Holding, the holding company of Solana, in exchange for a share of the dividends and the taxable loss generated by Solana. See note 1 to our Annual Consolidated Financial Statements.
(4) Solaben 2 and Solaben 3 are separate special purpose vehicles with separate agreements, but they are treated as a single platform.
(5) Itochu Corporation, a Japanese trading company, holds 30.0% of the shares in each of Solaben 2 and Solaben 3.
(6) Solacor 1 and Solacor 2 are separate special purpose vehicles with separate agreements but they are treated as a single platform.
(7) JGC Corporation, a Japanese engineering company, holds 13.0% of the shares in each of Solacor 1 and Solacor 2.
(8) PS10 and PS20 are separate special purpose vehicles with separate agreements but they are treated as a single platform.
(9) Helioenergy 1 and Helioenergy 2 are separate special purpose vehicles with separate agreements but they are treated as a single platform.
(10) Helios 1 and Helios 2 are separate special purpose vehicles with separate agreements but they are treated as a single platform.
(11) Solnova 1, Solnova 3 and Solnova 4 are separate special purpose vehicles with separate agreements but they are treated as a single platform.
(12) Solaben 1 and Solaben 6 are separate special purpose vehicles with separate agreements, but they are treated as a single platform.
(13) Instituto para la Diversificacion y Ahorro de la Energia, or IDEA, a Spanish state-owned company, holds 20.0% of the shares in Seville PV.
(14) Industrial Development Corporation of South Africa owns 29.0% and Kaxu Community Trust owns 20.0% of Kaxu.
(15) Refers to the credit rating of the Republic of South Africa.
(16) Refers to the credit rating of Uruguay, as UTE is unrated.
(17) Algerian Energy Company, SPA owns 49.0% of Honaine and Valoriza Agua, S.L., subsidiary of Sacyr S.A., owns the remaining 25.5%.
(18) Algerian Energy Company, SPA owns 49.0% of Skikda and Valoriza Agua, S.L., subsidiary of Sacyr S.A., owns the remaining 16.8%.
(19) Previously named "Conventional Power."

Our assets and operations are organized into the following four business sectors:

Renewable Energy

Our renewable energy assets include two solar power plants in the United States, Solana and Mojave, each with a gross capacity of 280 MW and located in Arizona and California, respectively. Solana is a party to a PPA with Arizona Public Service Company and Mojave is a party to a PPA with Pacific Gas & Electric Company. Solana reached its Commercial Operations Date, or COD, on October 9, 2013 and Mojave reached COD on December 1, 2014.

Additionally, we own the following solar power plants in Spain with a total gross capacity of 682 MW: (i) Solaben 2/3, a 100 MW solar power complex; (ii) Solacor 1/2, a 100 MW solar power complex; (iii) PS10/20, a 31 MW solar power complex; (iv) Helioenergy 1/2, a 100 MW solar power complex; (v) Helios 1/2, a 100 MW solar power complex; (vi) Solnova 1/3/4, a 150 MW solar power complex; (vii) 74.99% of the shares and a 30-year usufruct of the economic rights of the remaining 25.01% of the shares of Solaben 1/6, a 100 MW solar power complex in Spain, which usufruct does not expire until September 2045; and (viii) an 80% stake in Seville PV, a 1 MW solar photovoltaic plant in Spain. All such projects receive market and regulated revenues under the economic framework for renewable energy projects in Spain.

We also own two onshore wind farms in Uruguay: Palmatir and Cadonal, each with a gross capacity of 50 MW. Each wind farm is subject to a 20-year U.S. dollar-denominated PPA with a state-owned utility company in Uruguay.

We also own 51.0% of Kaxu, a 100 MW solar power plant in South Africa. Kaxu is a party to a 20-year PPA with Eskom, the state-owned utility company in South Africa.

Finally, we own a 4 MW hydro in Peru. Mini-hydro has a 20-year concession agreement with the Peruvian Ministry of Energy.

Efficient Natural Gas Power

Our efficient natural gas (previously named “conventional”) power asset consists of ACT, a 300 MW cogeneration plant in Mexico. ACT is a party to a 20-year take-or-pay contract with Petroleos Mexicanos S.A. de C.V., or Pemex, for the sale of electric power and steam. Pemex also supplies the natural gas required for the plant at no cost to ACT, which insulates the project from natural gas price variations.

Electric Transmission

Our electric transmission assets consist of (i) three lines in Peru, ATN, ATN2 and ATS, spanning a total of 1,012 miles and (ii) three lines in Chile, Quadra 1, Quadra 2 and Palmucho, spanning a total of 87 miles.

ATN and ATS are subject to a U.S. dollar-denominated 30-year contract with the Peruvian Ministry of Energy. ATN2 is subject to a U.S. dollar-denominated 18-year contract with Minera Las Bambas mining company, which is owned by a partnership consisting of subsidiaries of China Minmetals Corporation, Guoxin International Investment Co. Ltd and CITIC Metal Co. Ltd and reached COD in June 2015. Quadra 1 and Quadra 2 are subject to a concession contract with Sierra Gorda SCM, a mining company owned by Sumitomo Corporation, Sumitomo Metal Mining and KGHM Polska Mietz. Palmucho is a six-mile electric transmission line and substation subject to a private concession agreement with a utility, Endesa Chile.

Water

Our water assets consist of (i) minority stakes in two desalination plants in Algeria, Honaine and Skikda, with an aggregate capacity of 10.5 M ft3 per day, which we acquired in February 2015. Each asset has a 30-year take-or-pay water purchase agreement with Sonatrach/Algerienne des Eaux.

Our Business Strategy

We are a company focused on owning and operating contracted assets across the renewable energy, efficient natural gas (previously named “conventional”) power, electric transmission line and water sectors in North America, South America and EMEA. We intend to grow our business, maintaining North America, South America and Europe as our core geographies.

We currently own or have interests in 22 assets, comprising 1,446 MW of renewable energy generation, 300 MW of efficient natural gas (previously named “conventional”) power generation, 10.5 M ft3 per day of water desalination and 1,099 miles of electric transmission lines. All of our assets have contracted revenues (regulated revenues in the case of our Spanish assets) with low-risk off-takers and collectively have a weighted average remaining contract life of approximately 19 years as of December 31, 2017.

Our primary business strategy is to generate stable cash flows with our portfolio of assets. With this, we intend to distribute a stable cash dividend to holders of our shares that we intend to grow over time, while ensuring the ongoing stability of our business.

We intend to grow our business mainly through acquisitions of contracted assets in operation, in the segments where we are already present, maintaining renewable energy as our main segment and with a focus in North and South America. We may complement this strategy by dedicating a limited portion of our growth to projects in development.

Our plan for executing this strategy includes the following key components:

Focus on stable, long-term contracted assets in renewable energy, efficient natural gas (previously named "conventional") power generation, electric transmission lines and water assets

We intend to focus on owning and operating these types of assets, for which we possess deep know-how, extensive experience and proven systems and management processes, as well as the critical mass to benefit from operating efficiencies and scale. We expect that this will allow us to maximize value and cash flow generation going forward. We intend to maintain a diversified portfolio in the future, as we believe these technologies will undergo significant growth in our targeted geographies.

Maintain geographic diversification across three principal geographic areas

Our focus on three core geographies, North America, South America and Europe, helps to ensure exposure to markets in which we believe the renewable energy, efficient natural gas power and electric transmission sectors will continue growing significantly.

Increase cash available for distribution by optimizing our existing assets

Some of our assets have not reached their target production levels yet and we believe that we can increase the cash flow generation of these assets through further management and optimization initiatives and in some cases through repowering. See "Item 3.D—Risk Factors—Risks Related to Our Assets—Certain of our facilities may not perform as expected."

Increase cash available for distribution through the acquisition of new assets in renewable energy, efficient natural gas (previously named "conventional") power and electric transmission

We will seek to grow our cash available for distribution and our dividend to shareholders by acquiring new contracted assets from AAGES, Abengoa, from third parties and from potential new future partners or sponsors. We have an exclusive ROFO agreement with Abengoa, which provides us with a right of first offer on certain Abengoa's assets in operation. In addition, we have a ROFO agreement with AAGES, which provides us with a right of first offer on AAGES' assets. We plan to sign similar agreements with other developers or asset owners or enter into partnerships with such developers or asset owners in order to acquire assets in operation or to invest directly or through investment vehicles in assets under development or construction, ensuring that such investments are always a small part of our total investments. Finally, we expect to acquire assets from third parties leveraging the local presence and network we have in the geographies and sectors where we operate. We believe that our know-how and operating expertise in our key markets together with a critical mass of assets in several geographic areas and the access to capital provided by being a listed company will permit us to successfully realize our growth plans.

Foster a low-risk approach

We intend to maintain, over time, a portfolio of contracted assets with a low-risk profile due to creditworthy offtake counterparties, long-term contracted revenues, over 80% of cash available for distribution in U.S. dollars or euros, hedging euros for the upcoming 24 months on a rolling basis and proven technologies in which we have significant experience, located in countries where we believe conditions to be stable and safe.

In certain situations, we could invest in assets before they enter into operation, in assets with shorter contracted revenue period or in assets with revenue contracted in currencies other than U.S. dollar or euro.

Additionally, our policies and management systems include thorough risk analysis and risk management processes that we apply whenever we acquire an asset, and which we review monthly throughout the life of the asset. Our policy is to insure all of our assets whenever economically feasible.

Maintain financial strength and flexibility

We intend to maintain a solid financial position through a combination of cash on hand and credit facilities. Conservative cash management may help us to mitigate any unexpected downturns that reduce our cash flow generation.

Our Competitive Strengths

We believe that we are well positioned to execute our business strategies because of the following competitive strengths:

Stable and predictable long-term cash flows with attractive tax profiles

We believe that our recently-developed asset portfolio has a highly stable, predictable cash flow profile consisting of predominantly long-life electric power generation and electric transmission assets that generate revenues under long-term fixed priced contracts or pursuant to regulated rates with creditworthy counterparties. Additionally, our facilities have minimal to no fuel risk. The offtake agreements for our assets have a weighted average remaining duration of approximately 19 years as of December 31, 2017, providing long-term cash flow stability and visibility. Additionally, our business strategy and hedging policy is intended to ensure a minimum of 80% of cash available for distribution in U.S. dollar or in euros, and to hedge the euro for the upcoming 24 months on a rolling basis. Furthermore, due to the fact that we are a U.K. resident company we should benefit from a more favorable treatment than would apply if we were a corporation in the United States when receiving dividends from our subsidiaries that hold our international assets because they should generally be exempt from U.K. taxation due to the U.K.'s distribution exemption. Based on our current portfolio of assets, which include renewable assets that benefit from an accelerated tax depreciation schedule, and current tax regulations in the jurisdictions in which we operate, we do not expect to pay significant income tax for a period of at least 10 years due to existing net operating losses, or NOLs, except for ACT in Mexico, where we do not expect to pay significant income taxes until the fifth or sixth year after our IPO (i.e., until 2019 or 2020) once we use existing NOLs. See "Item 3.D—Risk Factors—Risks Related to Taxation—Our future tax liability may be greater than expected if we do not utilize Net Operating Losses, or NOLs, sufficient to offset our taxable income," "Item 3.D—Risk Factors—Risks Related to Taxation—Our ability to use U.S. NOLs to offset future income may be limited" and "Item 3.D—Risk Factors—Risks Related to Taxation—Changes in our tax position can significantly affect our reported earnings and cash flows." Furthermore, based on our current portfolio of assets, we believe that there is minimal repatriation risk in the jurisdictions in which we operate. See "Item 3.D—Risk Factors—Risks Related to Our Business and the Markets in Which We Operate—We have international operations and investments, including in emerging markets that could be subject to economic, social and political uncertainties."

Highly diversified portfolio by geography and technology

We believe that our strategic exposure to international markets will allow us to pursue greater growth opportunities and achieve higher returns than we would if we had a narrow geographic or technological focus. Our portfolio of assets uses technologies that we expect to benefit from long-term trends in the electricity sector. Our renewable energy generation assets generate low or no emissions and serve markets where we expect growth in demand in the future. Additionally, our electric transmission lines connect electricity systems to key areas in their respective markets and we expect significant electric transmission investment in our geographies. As a result, we believe that we may be able to benefit from opportunities to repower some of our assets during the lives of our existing PPAs and to extend the terms of those contracts after current PPAs expire. We expect our well-diversified portfolio of assets by technology and geography to maintain cash flow stability.

Strong corporate governance with a majority independent board and an experienced and incentivized management team

Five of the eight members of our board of directors are independent from us and from Algonquin and Abengoa. Once the Share Sale is complete and the Shareholders Agreement comes into effect, Algonquin or AAGES will have the right to appoint two directors and thus the majority of the board of directors will be independent. We require a majority vote by our independent directors in connection with related party transactions, including acquisitions under the AAGES ROFO Agreement, the Abengoa ROFO Agreement and the Algonquin ROFO Agreement. Our management team has significant and valuable expertise in developing, financing, operating and managing renewable energy, efficient natural gas power and electric transmission assets. We believe their financial and tax management skills will help us achieve our financial targets and continue to grow on a cash accretive basis over the medium- to long-term. Additionally, we intend to encourage our management team to ensure that they focus on stable, long-term cash flow generation.

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Our Operations

Renewable energy

The following table presents our renewable energy assets, all of which are operational:

Assets	Type	Ownership	Location	Currency	Capacity (Gross)	Offtaker	Counterparty Credit Rating[1]	COD	Contract Years Left
Solana	Renewable (Solar)	100% Class B	Arizona (USA)	USD	280 MW	APS	A-/A3/A-	4Q 2013	26
Mojave	Renewable (Solar)	100%	California (USA)	USD	280 MW	PG&E	A-/A3/A-	4Q 2014	22
Solaben 2/3	Renewable (Solar)	70%	Spain	EUR	2x50 MW	Wholesale market/Spanish Electric System	BBB+/Baa2/A-	3Q 2012 & 2Q 2012	20 / 19
Solacor 1/2	Renewable (Solar)	87%	Spain	EUR	2x50 MW	Wholesale market/Spanish Electric System	BBB+/Baa2/A-	1Q 2012 & 1Q 2012	19 / 19
PS10/20[8]	Renewable (Solar)	100%	Spain	EUR	31 MW	Wholesale market/Spanish Electric System	BBB+/Baa2/A-	1Q 2007 & 2Q 2009	14 / 16
Helioenergy 1/2	Renewable (Solar)	100%	Spain	EUR	2x50 MW	Wholesale market/Spanish Electric System	BBB+/Baa2/A-	3Q 2011 & 4Q 2011	19 / 19
Helios ½	Renewable (Solar)	100%	Spain	EUR	2x50 MW	Wholesale market/Spanish Electric System	BBB+/Baa2/A-	2Q 2012 & 3Q2012	20 / 20
Solnova 1/3/4	Renewable (Solar)	100%	Spain	EUR	3x50 MW	Wholesale market/Spanish Electric System	BBB+/Baa2/A-	2Q 2010 & 2Q 2010 & 3Q 2010	17 / 17 / 18
Solaben 1/6	Renewable (Solar)	100%	Spain	EUR	2x50 MW	Wholesale market/Spanish Electric System	BBB+/Baa2/A-	3Q 2013	21 / 21
Seville PV	Renewable (Solar)	80%	Spain	EUR	1 MW	Wholesale market/Spanish Electric System	BBB+/Baa2/A-	3Q 2006	18
Kaxu	Renewable (Solar)	51%	South Africa	ZAR	100 MW	Eskom	BB/Baa3/ BB+[2]	1Q 2015	17
Palmatir	Renewable (Wind)	100%	Uruguay	USD	50 MW	Uruguay	BBB/Baa2/ BBB-[3]	2Q 2014	16
Cadonal	Renewable (Wind)	100%	Uruguay	USD	50 MW	Uruguay	BBB/Baa2/ BBB-[3]	4Q 2014	17
Mini-hydro Peru	Renewable (Hydro)	100%	Peru	USD	4 MW	Peru	BBB+/A3/ BBB+	2Q 2012	15

Notes:—

(1) Reflects counterparty's issuer credit ratings issued by S&P, Moody's and Fitch.

(2) Refers to the credit rating of the Republic of South Africa.

(3) Refers to the credit rating of Uruguay, as UTE is unrated.

Solana

Overview. The Solana Solar Project, or Solana, is a 250 MW net (280 MW gross) solar electric generation facility located in Maricopa County, Arizona, approximately 70 miles southwest of Phoenix. Arizona Solar One LLC, or Arizona Solar, owns the Solana project. Solana includes a 22-mile 230kV transmission line and a molten salt thermal energy storage system. The construction of Solana commenced in December 2010 and Solana reached COD on October 9, 2013.

Solana relies on a conventional parabolic trough solar power system to generate electricity. The parabolic trough technology has been utilized for over 25 years at the Solar Electric Generating Systems, SEGS, facilities located in the Mojave Desert in Southern California. Our 13 50-MW parabolic trough facilities in Spain have also used this technology since 2010. Solana produces electricity by means of an integrated process using solar energy to heat a synthetic petroleum-based fluid in a closed-loop system that, in turn, heats water to create steam to drive a conventional steam turbine. Solana employs a two-tank molten salt thermal energy storage system that provides an additional six hours of solar dispatchability to increase its efficiency.

ASUSHI Inc., the entity through which we indirectly invest in Solana, is not expected to pay U.S. federal income taxes in the next 10 years due to the relevant NOLs and NOL carryforwards generated by the application of tax incentives established in the United States, in particular MACRS accelerated depreciation.

Power Purchase Agreement. Solana has a 30-year, fixed-price PPA with Arizona Public Service Company, or APS, for at least 110% of the output of the project. The PPA provides for the sale of electricity at a fixed base price approved by the Arizona Corporation Commission with annual increases of 1.84% per year. The PPA includes on-going performance obligations and is intended to provide Arizona Solar with consistent and predictable monthly revenues that are sufficient to cover operating costs and debt service and to earn an equity return.

APS is a load serving utility based in Phoenix, Arizona. APS has senior unsecured credit ratings of A- from S&P, A3 from Moody's and A- from Fitch.

The PPA was initially executed in February 2008 and received final approval from the Arizona Corporation Commission in December 2008. The PPA was most recently amended and restated in December 2010. The PPA expires on October 9, 2043.

Engineering, Procurement and Construction Agreements. The construction of Solana was carried out by subsidiaries of Abengoa under an arm's-length, fixed-price and date-certain engineering, procurement and construction contract, or an EPC contract, that was executed on December 20, 2010. Abengoa completed construction of Solana on October 9, 2013. Abengoa constructed Solana using equipment from leading suppliers, including two 140 MW (gross) steam turbines supplied by Siemens.

Arizona Solar's EPC contract contains warranties that protect Arizona Solar against defects in design, materials and workmanship for one year after completion and under these warranties Abengoa is required to conduct certain repairs and improvements to ensure the plant reaches its technical capacity. Solana has not yet achieved its technical capacity on a continuous basis. During 2016, 2017 and 2018, repairs and improvements were and will be conducted on three plant systems: the steam generator, the water plant and the storage heat exchangers. In July 2016, the solar field was damaged after a severe wind event and in 2017, we received insurance compensation for damages and loss of revenue. In July 2017, there was an incident with electric transformers, which caused the plant to produce at a reduced capacity during July and part of August. All the necessary repairs were completed in August and we received a significant portion of the insurance compensation in 2017. Additionally, due to the repairs to the heat exchangers of the storage system, we plan to replace one of the heat exchangers during 2018. In November 2017, in the context of the agreement reached between Abengoa and Algonquin for the acquisition by Algonquin of 25.0% of our shares and based on the obligations of Abengoa under an EPC contract, the DOE signed a consent in relation to the Solana and Mojave projects which reduces the minimum ownership required by Abengoa in us from 30.0% to 16.0%, subject to certain conditions precedent. The main conditions precedent included several payments by Abengoa to Solana before December 2017 and March 2018 as a result of its obligations as EPC contractor, for a total amount of $120 million. Additionally, Abengoa has recognized other obligations with Solana for $6.5 million per half-year over 10 years starting in December 2018. In December 2017, Solana received $42.5 million which was used to repay project finance debt. Solana is expected to receive in March 2018 an additional $77.5 million. From this amount $52.5 million is expected to be used to repay project debt and $25 million is expected to cover other current and potential future Abengoa obligations.

Operations & Maintenance. ASI Operations LLC, or ASI Operations, a wholly-owned subsidiary of Abengoa, provides operations and maintenance, or O&M, services for Solana, focused exclusively on personnel. ASI Operations has agreed to operate the facility in accordance with prudent utility practices, to ensure compliance with all applicable government and agency permits, licenses, approvals and PPA terms, and to assist Arizona Solar in connection with the procurement of all necessary support and ancillary services. The Operations and Maintenance Agreement, or an O&M agreement, executed on December 20, 2010 between ASI Operations and Arizona Solar is a 30-year cost-reimbursable contract plus a fixed fee, which is indexed to U.S. CPI. A variable fee is to be paid in periods when the project's annual net operating profits exceed the target annual net operating profit. Payments to third-party suppliers are made directly by Arizona Solar. We expect that the variable fee will provide ASI Operations with a significant long-term interest in the success of the project, which we expect will align its interests with those of Arizona Solar.

Project Level Financing. Arizona Solar executed a loan guarantee agreement with the DOE on December 20, 2010, to provide a loan guarantee in connection with a two-tranche loan of approximately $1.445 billion from the FFB. The FFB loan had a short-term tranche of $450 million as of December 31, 2013, that was repaid in April 2014 with the proceeds from the Investment Tax Credit Cash Grant, or ITC Cash Grant, that the project received from the U.S. Treasury. The FFB loan has a long-term tranche payable over a 29-year term with the cash generated by the project. The principal balance of this tranche was $882 million as of December 31, 2017. The loan is denominated in U.S. dollars. The FFB loan has a fixed average interest rate of 3.67%.

The financing arrangement permits dividend distributions on a semi-annual basis as long as the debt service coverage ratio for the previous four fiscal quarters is at least 1.20x (1.30x debt service coverage ratio and operating performance above certain thresholds for distributions before December 31, 2019) and the projected debt service coverage ratio for the next four fiscal quarters is at least 1.20x.

Partnerships. On September 30, 2013, Abengoa entered into an agreement with Liberty, pursuant to which Liberty agreed to invest $300 million in Class A membership interests of ASO Holdings Company LLC, the parent of Arizona Solar, in exchange for the right to receive 61.20% of taxable losses and distributions until such time as Liberty reaches a certain rate of return, or the Flip Date. Given that Solana has not performed as expected, Liberty will require additional distributions in order to reach the agreed rate of return. After the Flip Date, Liberty will be entitled to receive 22.60% of taxable losses and distributions. During the year 2017, we agreed with Liberty to increase their information rights and their participation in decisions for Arizona Solar. All figures in this annual report take into account Liberty's share of dividends. We indirectly own 100% of the Class B membership interests in ASO Holdings Company LLC.

Mojave

Overview. The Mojave Solar Project, or Mojave, is a 250 MW net (280 MW gross) solar electric generation facility located in San Bernardino County, California, approximately 100 miles northeast of Los Angeles. Abengoa commenced construction of Mojave in September 2011. Mojave completed construction and reached COD on December 1, 2014. Mojave Solar LLC, or Mojave Solar, owns the Mojave project.

Mojave relies on a conventional parabolic trough solar power system to generate electricity and is similar to Solana with respect to technology and general design. The main difference between Solana and Mojave is that Mojave does not have a molten salt storage system, as the offtaker did not require one.

ASHUSA Inc., the entity through which we indirectly invest in Mojave, is not expected to pay federal income tax in the next 10 years due to the relevant NOLs and NOL carryforwards generated by the application of tax incentives established in the United States, in particular MACRS accelerated depreciation.

Power Purchase Agreement. Mojave has a 25-year, fixed-price PPA with Pacific Gas & Electric Company, or PG&E, for 100% of the output of Mojave. The PPA began on COD. The PPA provides for the sale of electricity at a fixed base price with seasonal adjustments and adjustments for time of delivery. Mojave Solar can deliver and receive payment for at least 110% of contracted capacity under the PPA.

PG&E, a utility based in San Francisco, is one of the largest integrated natural gas and electric utilities in the United States. PG&E has senior unsecured credit ratings of A- from S&P, A3 from Moody's and A- from Fitch.

Engineering, Procurement and Construction Agreement. The construction of Mojave was carried out by subsidiaries of Abengoa, or the contractor, under an arm's-length, fixed-price EPC contract that was executed on September 12, 2010. Mojave issued a "full notice to proceed" on March 7, 2012, and, as mentioned above, reached COD on December 1, 2014. Mojave's key equipment has been supplied by leading companies, including two twin turbines from General Electric. Under the EPC agreement with Mojave, since construction ended after the scheduled date, Abengoa paid certain amounts in the form of subordinated debt, which would only need to be reimbursed if during or at the end of the guarantee period certain conditions are met. Otherwise these amounts would become liquidated damages. We are currently evaluating if those conditions have been met.

Operations & Maintenance. ASI Operations provides O&M services for Mojave focused exclusively on personnel. Under the terms of the O&M agreement between ASI Operations and Mojave Solar, ASI Operations has agreed to operate the facility in accordance with prudent utility practices, to ensure compliance with all applicable government and agency permits, licenses, approvals and PPA terms, and to assist Mojave Solar in connection with the procurement of all necessary support and ancillary services. The O&M agreement is a cost-reimbursable contract plus a combination of fixed and variable fees. Payments to third-party suppliers are made directly by Arizona Solar. The fixed fee increases by 2.5% each year. Mojave Solar pays the variable fee in periods when the project's annual net operating profits exceed the target annual net operating profit. We expect that the variable fee will provide ASI Operations with a significant long-term interest in the success of the project, which we expect will align its interests with those of Mojave Solar.

Project Level Financing. Mojave Solar executed a Loan Guarantee Agreement with the DOE on September 12, 2011, to provide a loan guarantee in connection with a two-tranche FFB loan of approximately $1,202 million. The FFB loan had a short-term tranche of $336 million as of December 31, 2014 that Mojave Solar repaid in October 2015 with the proceeds from the ITC Cash Grant that the project received from the U.S. Treasury. The FFB loan has a long-term tranche payable over a 25-year term with the cash generated by the project. The principal balance of this tranche was $758 million as of December 31, 2017. The loan is denominated in U.S. dollars. The FFB loan has an average fixed interest rate of 2.75% and each disbursement is linked to the U.S. Treasury bond with the maturity of that disbursement.

The financing arrangement permits dividend distributions on a semi-annual basis after the first principal repayment of the long-term tranche, as long as the debt service coverage ratio for the previous four fiscal quarters is at least 1.20x and the projected debt service coverage ratio for the next four fiscal quarters is at least 1.20x.

Solaben 2/3

Overview. The Solaben 2 and Solaben 3 projects are two 50 MW solar power plants located in the municipality of Logrosan, Spain. Solaben 2 reached COD in July 2012 and Solaben 3 reached COD in May 2012. Solaben Electricidad Dos, S.A., or SE2, owns Solaben 2 and Solaben Electricidad Tres, S.A., or SE3, owns Solaben 3.

Solaben 2 and Solaben 3 each rely on a conventional parabolic trough solar power system to generate electricity. The technology is similar to the technology used in other solar power plants that we own in the United States and Spain.

Solaben 2 and Solaben 3 benefit from the tax accelerated depreciation regime established by the Spanish Corporate Income Tax Act and the plants are not expected to pay significant income taxes in the next 10 years.

Regulation. Renewable energy projects in Spain sell the power they produce into the wholesale electricity market and receive additional payments from the Comision Nacional de los Mercados y de la Competencia, or CNMC, the Spanish state-owned regulator.

Solar power plants receive, in addition to the revenues from the sale of electricity in the market, two monthly payments. These payments consist of: (i) a fixed monthly payment based on installed capacity and (ii) a variable payment based on net electricity produced. There is a maximum number of production hours per year beyond which no variable payment is received. The regulation also includes a minimum number of yearly hours of generation, under which the plant would receive no regulated payments for that year and another higher threshold below which regulated payments would be reduced for a certain year. Those numbers are 35.0% and 60.0% of the maximum yearly hours, respectively. We expect that a plant would fail to achieve these thresholds only in cases of major breakdowns. See “Item 4.B—Business Overview—Regulation—Regulation in Spain.”

Spain has senior unsecured credit ratings of BBB+ from S&P, Baa2 from Moody’s and A- from Fitch.

Operations & Maintenance. Abengoa Solar Espana, S.A., or ASE, is the contractor for O&M services at Solaben 2/3. ASE has agreed to operate the facility in accordance with prudent utility practices, ensure compliance with all applicable government and agency permits, licenses and approvals, and feed-in tariff terms, and to assist Solaben 2/3 in connection with the procurement of all necessary support and ancillary services. Each O&M agreement is a 20-year, all-in contract that expires on the 20th anniversary of the COD, under certain circumstances the contract can be terminated by us before the expiration date.

Project Level Financing. SE2 and SE3 each entered into a 20-year loan agreement with a syndicate of banks formed by the Bank of Tokyo-Mitsubishi, Mizuho, HSBC and Sumitomo Mitsui Banking Corporation on December 16, 2010. Each loan is denominated in euros. The loan for Solaben 2 was for €169.3 million and the loan for Solaben 3 was for €171.5 million. The banks providing these loans obtained commercial and political risk insurance from Nippon Export and Investment Insurance, which allowed for lower financing costs. The interest rate for each loan is a floating rate based on EURIBOR plus a margin of 1.5%. Each loan was initially 80% hedged with the same banks providing the financing. The hedge was structured 50% through a swap set at approximately 3.7% and 50% through a cap with a 3.75% strike. In November 2013, SE2 and SE3 hedged through 2017 the remaining 20% exposure through a cap with a 0.75% strike. Furthermore, in 2017, we contracted additional caps with a 1% strike covering 19.1% of the principal of Solaben 2 and 20% of the principal of Solaben 3. Both caps hedge the interest rate from the middle of 2017 through 2025.

The outstanding amount of these loans as of December 31, 2017 was €136 million for Solaben 2 and €139 million for Solaben 3.

The financing arrangements permit cash distribution to shareholders once per year if the audited financials for the prior fiscal year indicate a debt service coverage ratio of at least 1.10x.

Partnerships. Itochu Corporation, a Japanese trading company, holds a 30% stake in the economic rights of each of Solaben 2 and Solaben 3.

Solacor 1/2

Overview. The Solacor 1/2 project is a 100 MW solar power complex located in the municipality of El Carpio, Spain. Abengoa commenced construction of Solacor 1/2 in September 2010. COD was reached in February 2012 for Solacor 1 and in March 2012 for Solacor 2. JGC Corporation, or JGC, a Japanese engineering company, currently owns 13% of Solacor 1/2.

Solacor 1/2 relies on a conventional parabolic trough solar power system to generate electricity. The technology is similar to the technology used in other solar power plants that we own in Spain.

We hold 87% of the shares of the entity holding Solacor 1 and Solacor 2.

Solacor 1 and Solacor 2 benefit from the tax accelerated depreciation regime established by the Spanish Corporate Income Tax Act. Most plants in Spain are part of the tax consolidation group that is not expected to pay significant income taxes in the next 10 years.

Regulation. Renewable energy projects in Spain sell the power they produce into the wholesale electricity market and receive additional payments from the CNMC.

Solar power plants receive, in addition to the revenues from the sale of electricity in the market, two monthly payments. These payments consist of: (i) a fixed monthly payment based on installed capacity and (ii) a variable payment based on net electricity produced. There is a maximum number of production hours per year beyond which no variable payment is received. The regulation also includes a minimum number of yearly hours of generation, under which the plant would receive no regulated payments for that year and another higher threshold below which regulated payments would be reduced for a certain year. Those numbers are 35.0% and 60.0% of the maximum yearly hours, respectively. We expect that a plant would fail to achieve these thresholds only in cases of major breakdowns. See “Item 4.B—Business Overview—Regulation—Regulation in Spain.”

Spain has senior unsecured credit ratings of BBB+ from S&P, Baa2 from Moody’s and A- from Fitch.

Operations & Maintenance. ASE is the contractor for O&M services at Solacor 1/2. ASE has agreed to operate the facility in accordance with prudent utility practices, ensure compliance with all applicable government and agency permits, licenses and approvals, and feed-in tariff terms, and to assist Solacor 1/2 in connection with the procurement of all necessary support and ancillary services. Each O&M agreement is a 25-year, all-in contract that expires on the 25th anniversary of the COD, under certain circumstances the contract can be terminated by us before the expiration date.

Project Level Financing. Solacor 1/2 entered into 20-year loan agreements with a syndicate of banks formed by BNP Paribas, Mizuho, HSBC and SMBC on August 6, 2010. The loans are denominated in euros. The loans for Solacor 1/2 totaled €353 million. The banks providing these loans obtained commercial and political risk insurance from Nippon Export and Investment Insurance, which allowed for lower financing costs. The interest rate for the loans is a floating rate based on EURIBOR plus a margin of 1.5%. The loans were initially approximately 82% hedged with the same banks providing the financing. The hedge was structured 54% through a swap set at approximately 3.20% and 28% through a cap with a 3.25% strike. Furthermore, in 2017, we contracted additional caps with a 1% strike covering 19.3% of the principal of Solacor 1 and 18.2% of the principal of Solacor 2. Both caps hedge the interest rate from the middle of 2017 through 2025. The total outstanding amount of these loans as of December 31, 2017 was €275 million.

These financing arrangements permit cash distribution to shareholders once per year if the audited financials for the prior fiscal year indicate a debt service coverage ratio of at least 1.10x.

Partnerships. On December 31, 2015, JGC Corporation, a Japanese engineering company, held a 26% stake in the economic rights in Solacor 1/2. On January 7, 2016, we closed the acquisition of 13% of the shares of Solacor 1/2 from JGC Corporation, which reduced their ownership in Solacor 1/2 to 13%.

PS10/20

Overview. PS10/20 is a 31 MW solar power complex located in the municipality of Sanlucar la Mayor, Spain. PS10 reached COD in March 2007 and PS20 reached COD in May 2009.

PS10/20 benefits from the tax accelerated depreciation regime established by the Spanish Corporate Income Tax Act applicable to the tax consolidated group into which the plants are included.

Regulation. Renewable energy projects in Spain sell the power they produce into the wholesale electricity market and receive additional payments from CNMC.

Solar power plants receive, in addition to the revenues from the sale of electricity in the market, two monthly payments. These payments consist of: (i) a fixed monthly payment based on installed capacity and (ii) a variable payment based on net electricity produced. There is a maximum number of production hours per year beyond which no variable payment is received. The regulation also includes a minimum number of yearly hours of generation, under which the plant would receive no regulated payments for that year and another higher threshold below which regulated payments would be reduced for a certain year. Those numbers are 35.0% and 60.0% of the maximum yearly hours, respectively. We expect that a plant would fail to achieve these thresholds only in cases of major breakdowns. See "Item 4.B—Business Overview—Regulation—Regulation in Spain."

Spain has senior unsecured credit ratings of BBB+ from S&P, Baa2 from Moody's and A- from Fitch.

Operations & Maintenance. ASE is the contractor for O&M services at PS10/20. ASE has agreed to operate the facility in accordance with prudent utility practices, ensure compliance with all applicable government and agency permits, licenses and approvals, and feed-in tariff terms, and to assist PS10/20 in connection with the procurement of all necessary support and ancillary services. Each O&M agreement is a 21-year all-in contract that expires on the 21st anniversary of COD.

Project Level Financing. PS10 entered into a 21.5-year loan agreement with a syndicate of banks formed by Bankia and Natixis on November 17, 2006. On June 14, 2007, the loan agreement was entered into a novation in order to include in the syndicate of banks the European Investment Bank and Caja de Ahorros del Mediterraneo, which was later acquired by Banco Sabadell, S.A. The loan was for €43.4 million. The interest rate for the loan is a floating rate based on EURIBOR plus a margin of 1.0% to 1.10% (depending on the level of the debt service coverage ratio). The loan was initially 100% hedged with the same banks providing the financing. The hedge was structured 30% through a swap set at approximately 4.07% and 70% through a cap with a 4.25% strike. Furthermore, in 2017, we contracted an additional cap with a 1% strike covering 35.0% of the principal of PS10 from the middle of 2017 through 2025. The outstanding amount of this loan as of December 31, 2017 was €27 million.

PS20 entered into a 24.5-year loan agreement with a syndicate of banks formed by Bankia and Natixis Banques Populaires, Spanish Branch on November 17, 2006. On June 14, 2007, the loan agreement was entered into a novation in order to include in the syndicate of banks the European Investment Bank and Caja de Ahorros del Mediterraneo, which was later acquired by Banco Sabadell, S.A. The loan was for €94.6 million. The interest rate for the loan is a floating rate based on EURIBOR plus a margin of 1.0% to 1.10% (depending on the level of the debt service coverage ratio). The loan was initially 100% hedged with the same banks providing the financing. The hedge was structured 30% through a swap set at approximately 4.07% and 70% through a cap with a 4.5% strike. Furthermore, in 2017, we contracted additional caps with a 1% strike covering 35.0% of the principal of PS20 from the middle of 2017 through 2025. The outstanding amount of this loan as of December 31, 2017 was €67 million.

These financing arrangements permit cash distribution to shareholders once per year if the audited financials for the prior fiscal year indicate a debt service coverage ratio of at least 1.10x.

Helios 1/2

Overview. The Helios 1/2 project is a 100 MW concentrating solar power facility located in the municipality of Arenas de San Juan, Puerto Lapice and Villarta de San Juan, Spain. Helios 1 reached COD in the second quarter of 2012 and Helios 2 reached COD in the third quarter of 2012. We indirectly own 100% of Helios 1/2.

Helios 1/2 relies on a conventional parabolic trough concentrating solar power system to generate electricity. This technology is similar to the technology used in other solar power plants that we own in Spain.

Helios 1/2 benefits from the tax accelerated depreciation regime established by the Spanish Corporate Income Tax Act applicable to the tax consolidated group into which the plants are included.

Regulation. Renewable energy projects in Spain sell the power they produce into the wholesale electricity market and receive additional payments from CNMC.

Solar power plants receive, in addition to the revenues from the sale of electricity in the market, two monthly payments. These payments consist of: (i) a fixed monthly payment based on installed capacity and (ii) a variable payment based on net electricity produced. There is a maximum number of production hours per year beyond which no variable payment is received. The regulation also includes a minimum number of yearly hours of generation, under which the plant would receive no regulated payments for that year and another higher threshold below which regulated payments would be reduced for a certain year. Those numbers are 35.0% and 60.0% of the maximum yearly hours, respectively. We expect that a plant would fail to achieve these thresholds only in cases of major breakdowns. See "Item 4.B—Business Overview—Regulation—Regulation in Spain."

Spain has senior unsecured credit ratings of BBB+ from S&P, Baa2 from Moody's and A- from Fitch.

Operation & Maintenance. ASE is the contractor for O&M services at Helios 1/2. ASE has agreed to operate the facility in accordance with prudent utility practices, ensure compliance with all applicable government and agency permits, licenses and approvals, and feed-in tariff terms, as well as to assist Helios 1/2 in connection with the procurement of all necessary support and ancillary services. The O&M agreement is a 25-year, all-in contract that expires on the 25th anniversary of the COD.

Project Level Financing. On June 6, 2011, Helios 1 entered into a 20-year loan agreement for €144.2 million with a syndicate of banks formed by Santander, Caixa Bank, Banif Investment Bank, Bankia, Kfw IPEX-Bank, Helaba and ICO. The interest rate for the loan is a floating rate based on EURIBOR (six months) plus a margin of 3.50% until August 12, 2016, plus a margin of 3.75% from August 10, 2016 to August 10, 2018 and plus a margin of 4.25% from August 10, 2018. The loan was initially approximately 75% hedged with the same banks providing the financing. The hedge was structured 100% through a swap set at approximately 3.85%

On June 6, 2011, Helios 2 entered into a 20-year loan agreement for €145.1 million with a syndicate of banks formed by Santander, Caixa Bank, Banif Investment Bank, Bankia, Kfw IPEX-Bank, Helaba and ICO. The interest rate for the loan is a floating rate based on EURIBOR (six months) plus a margin of 3.50% until August 12, 2016, plus a margin of 3.75% from August 10, 2016 to August 10, 2018 and plus a margin of 4.25% as of August 10, 2018. The loan was initially approximately 75% hedged with the same banks providing the financing. The hedge was structured 100% through a swap set at approximately 3.85%. Furthermore, in 2017, we contracted additional caps with a 1% strike covering 12.5% of the principal of both Helios 1 and Helios 2 from the middle of 2017 through 2025.

The total outstanding amount of these loans as of December 31, 2017 was €251 million.

The financing agreements of both plants permit cash distributions to shareholders once per year if the audited financials for the prior fiscal year indicate a debt service coverage ratio of at least 1.15x.

Helios 1/2 projects have a "cash-sweep" mechanism in the financing agreements by which all the cash generated by the projects from 2019 will be paid directly to the lenders. We expect to refinance Helios 1/2 before 2019 although we cannot guarantee it.

Helioenergy 1/2

Overview. Helioenergy 1/2 is a 100 MW solar power complex located in Ecija, Spain and reached COD in the second half of 2011. We indirectly own 100% of Helioenergy 1/2.

Helioenergy 1/2 relies on a conventional parabolic trough concentrating solar power system to generate electricity. This technology is similar to the technology used in other solar power plants that we own in Spain.

Helioenergy 1/2 benefits from the tax accelerated depreciation regime established by the Spanish Corporate Income Tax Act applicable to the tax consolidated group into which the plants are included.

Regulation. Renewable energy projects in Spain sell the power they produce into the wholesale electricity market and receive additional payments from CNMC.

Solar power plants receive, in addition to the revenues from the sale of electricity in the market, two monthly payments. These payments consist of: (i) a fixed monthly payment based on installed capacity and (ii) a variable payment based on net electricity produced. There is a maximum number of production hours per year beyond which no variable payment is received. The regulation also includes a minimum number of yearly hours of generation, under which the plant would receive no regulated payments for that year and another higher threshold below which regulated payments would be reduced for a certain year. Those numbers are 35.0% and 60.0% of the maximum yearly hours, respectively. We expect that a plant would fail to achieve these thresholds only in cases of major breakdowns. See “Item 4.B—Business Overview—Regulation—Regulation in Spain.”

Spain has senior unsecured credit ratings of BBB+ from S&P, Baa2 from Moody’s and A- from Fitch.

Operation & Maintenance. ASE is the O&M services contractor for Helioenergy 1/2. ASE agreed to operate the facility in accordance with prudent utility practices, ensure compliance with all applicable government and agency permits, licenses and approvals, and feed-in tariff terms, as well as to assist Helioenergy 1/2 in connection with the procurement of all necessary support and ancillary services. The O&M agreement is a 20-year, all-in contract that expires on the 20th anniversary of the COD.

Project Level Financing. On May 6, 2010, Helioenergy 1 entered into an 18-year loan agreement for €158.2 million with a syndicate of banks consisting of Santander, Barclays Bank, Bankia, Credit Agricole CIB, Caixa Bank, Societe Generale, SMBC, Banco Popular, Bankinter and Unicaja. The interest rate for the loan is a floating rate based on EURIBOR plus a margin of 3.25% The loan was initially approximately 80% hedged with the same banks providing the financing. The hedge was structured 100% through a swap set at approximately 3.8205% strike.

On May 6, 2010, Helioenergy 2 entered into an 18-year loan agreement for €158.2 million with a syndicate of banks formed by Santander, Barclays Bank, Bankia, Credit Agricole CIB, Caixa Bank, Societe Generale, SMBC, Banco Popular, Bankinter and Unicaja. The loan is denominated in euro. The interest rate for the loan is a floating rate based on EURIBOR plus a margin of 3.25% The loan was initially approximately 80% hedged with the same banks providing the financing. The hedge was structured 80% through a swap set at approximately 3.8205% strike. Furthermore, in 2017, we contracted additional caps with a 1% strike covering 10% of the principal of both Helioenergy 1 and Helioenergy 2 from the middle of 2017 through 2025.

As of December 31, 2017, the outstanding amount of these loans was €256 million. The financing arrangements permit cash distributions to shareholders once per year if the audited financials for the prior fiscal year indicate a debt service coverage ratio of at least 1.15x.

Solnova 1/3/4

Overview. The Solnova 1/3/4 project is a 150 MW concentrating solar power facility located in the municipality of Sanlucar la Mayor, Spain. Solnova 1 and Solnova 3 projects reached COD in the second quarter of 2010 and Solnova 4 reached COD in the third quarter of 2010.

Solnova 1/3/4 relies on a conventional parabolic trough concentrating solar power system to generate electricity. This technology is similar to the technology used in other solar power plants that we own in Spain.

Solnova 1/3/4 benefits from the tax accelerated depreciation regime established by the Spanish Corporate Income Tax Act applicable to the tax consolidated group into which the plants are included.

Regulation. Renewable energy projects in Spain sell the power they produce into the wholesale electricity market and receive additional payments from CNMC. Solar power plants receive, in addition to the revenues from the sale of electricity in the market, two monthly payments. These payments consist of: (i) a fixed monthly payment based on installed capacity and (ii) a variable payment based on net electricity produced. There is a maximum number of production hours per year beyond which no variable payment is received. The regulation also includes a minimum number of yearly hours of generation, under which the plant would receive no regulated payments for that year and another higher threshold below which regulated payments would be reduced for a certain year. Those numbers are 35.0% and 60.0% of the maximum yearly hours, respectively. We expect that a plant would fail to achieve these thresholds only in cases of major breakdowns. See "Item 4.B—Business Overview—Regulation—Regulation in Spain."

Taking into account the minimum thresholds and the historical performance of the plants, we expect that the plants will reach the minimum generation required.

Spain has senior unsecured credit ratings of BBB+ from S&P, Baa2 from Moody's and A- from Fitch.

Operation & Maintenance. ASE is the O&M services contractor for Solnova Solar Platform. ASE has agreed to operate the facility in accordance with prudent utility practices, ensure compliance with all applicable government and agency permits, licenses and approvals, and feed-in tariff terms, as well as to assist Solnova in connection with the procurement of all necessary support and ancillary services. The O&M agreement is a 25-year, all-in contract that expires on the 25th anniversary of COD.

Project Level Financing. On December 18, 2007, Solnova 1 entered into a 22-year loan agreement for €233.4 million with a syndicate of banks consisting of Societe Generale, Santander, Credit Agricole CIB, Natixis, Banco Sabadell (Sabadell y Dexia), Credit Industriel et Commercial, Kfw IPEX-Bank, IKB Deutsche Industriebank, SMBC, Caixa Bank, DEPFA Bank, Landesbank Baden – Wurttemberg and BEI. The interest rate for the loan is a floating rate based on EURIBOR (six months) plus a margin in the range of 1.15% up to 1.25%, depending on the debt services coverage ratio. The loan was initially 80% hedged with the same banks providing the financing. The hedge was structured 100% through a swap set at approximately 4.76% strike. Furthermore, in 2017, we contracted an additional cap with a 1% strike covering 20% of the principal of Solnova 1 from the middle of 2017 through 2025.

On January 15, 2008, Solnova 3 entered into a 22-year loan agreement for €227.5 million with a syndicate of banks formed by Societe Generale, Santander, Credit Agricole CIB, Natixis, Banco Sabadell, Credit Industriel et Commercial, Kfw IPEX-Bank, IKB Deutsche Industriebank, SMBC, Caixa Bank, DEPFA Bank, Landesbank Baden – Wurttemberg and BEI. The interest rate for the loan is a floating rate based on EURIBOR (six months) plus a margin in the range from 1.15% up to 1.25%, depending on the debt services coverage ratio. The loan was initially 80% hedged with the same banks providing the financing. The hedge was structured 30% through a swap set at approximately 4.34% cost and 70% through a cap at approximately 4.65%. Furthermore, in 2017, we contracted an additional cap with a 1% strike covering 44% of the principal of Solnova 3 from the middle of 2017 through 2025.

On August 5, 2008, Solnova 4 entered into a 22-year loan agreement for €217.1 million with a syndicate of banks formed by Santander, Bankia, Credit Agricole CIB, Banco Sabadell (Sabadell y Dexia), ING Belgium, Kfw IPEX-Bank, Landesbank Baden-Wurttemberg, Natixis, Societe Generale and UBI Banca. The interest rate for the loan is a floating rate based on EURIBOR (six months) plus a margin in the range from 1.50% up to 1.60%, depending on the debt services coverage ratio. The loan was initially 80% hedged with the same banks providing the financing. The hedge was structured 100% through a swap set at approximately 4.87% strike. Furthermore, in 2017, we contracted an additional cap with a 1% strike covering 8.3% of the principal of Solnova 4 from the middle 2017 through 2025.

As of December 31, 2017, the outstanding amount of these loans was €509 million.

The financing arrangements of the three plants permit cash distributions to shareholders once per year if the audited financials for the prior fiscal year indicate a debt service coverage ratio of at least 1.15x. for Solnova 1/3/4.

Solaben 1/6

Overview. Solaben 1/6 is a 100 MW solar power facility located in the municipality of Logrosan, Spain. Solaben 1/6 reached COD in the third quarter of 2013.

Solaben 1/6 relies on a conventional parabolic trough concentrating solar power system to generate electricity. This technology is similar to the technology used in other solar power plants that we own in Spain.

Solaben 1/6 benefits from the tax accelerated depreciation regime established by the Spanish Corporate Income Tax Act. Solaben 1 /6 is not expected to pay significant income taxes in the upcoming years.

Regulation. Renewable energy projects in Spain sell the power they produce into the wholesale electricity market and receive additional payments from CNMC.

Solar power plants receive, in addition to the revenues from the sale of electricity in the market, two monthly payments in order to achieve the specific rate of return. These payments are comprised of: (i) a fixed monthly payment based on installed capacity and (ii) a variable payment based on net electricity produced. There is a maximum number of production hours per year beyond which no variable payment is received. The regulation also includes a minimum number of yearly hours of generation, under which the plant would receive no regulated payments and another higher threshold below which regulated payments would be reduced for a certain year. Those numbers are 35.0% and 60.0% of the maximum yearly hours, respectively. We expect that a plant would fail to achieve these thresholds only in cases of major breakdowns.

Spain has senior unsecured credit ratings of BBB+ from S&P, Baa2 from Moody's and A- from Fitch.

Operation & Maintenance. ASE is the O&M services contractor for Solaben 1/6. ASE has agreed to operate the facility in accordance with prudent utility practices, ensure compliance with all applicable government and agency permits, licenses and approvals, and feed-in tariff terms, as well as to assist Solaben 1/6 in connection with the procurement of all necessary support and ancillary services. Each O&M agreement is a 25-year, all-in contract that expires on the 25th anniversary of the COD.

Project Level Financing. On September 30, 2015, Solaben Luxembourg S.A., a holding company of the two project companies, issued a project bond for €285 million. The bonds mature in December 2034. The bonds have a coupon of 3.758% and interest are payable in semi-annual instalments on June 30 and December 31 of each year. The principal of the bonds is amortized over the life of the bonds. The bonds permit dividend distributions twice a year until September 30, 2019 and once a year after September 30, 2019. The debt service coverage ratio must be at least 1.30 until December 31, 2018, and 1.40 after January 1, 2019. The outstanding amount of the project bonds as of December 31, 2017 was €246 million.

Seville PV

Seville PV is a 1 MW photovoltaic farm located alongside PS 10/20 and Solnova 1/3/4, in Sanlucar La Mayor, Spain.

Seville PV is subject to the same regulations as our other solar facilities in Spain except that it has a regulatory life of 30 years. See “Item 4.B—Business Overview—Regulation—Regulation in Spain.”

Taking into account the minimum thresholds and the historical performance of Seville PV, we expect that it will reach the minimum generation required.

Spain has senior unsecured credit ratings of BBB+ from S&P, Baa2 from Moody’s and A- from Fitch.

Seville PV has an O&M agreement in place with Prodiel and does not have any project debt.

Kaxu

Overview. Kaxu Solar One Solar, or Kaxu, is a 100 MW net solar conventional parabolic trough project with a molten salt thermal energy storage system and is located in Pofadder, Northern Cape Province, South Africa. We, through ABY Solar South Africa (Pty) Ltd, own 51% of the Kaxu project. The project company, Kaxu Solar One (Pty) Ltd., is currently owned by: us (51%), Industrial Development Corporation of South Africa (29%) and Kaxu Community Trust (20%). The project reached COD in January 2015.

Kaxu relies on a conventional parabolic trough solar power system to generate electricity. This technology is similar to the technology used in solar power plants that we own in Spain.

According to the tax accelerated depreciation regime established by the South African Corporate Income Tax Act, Kaxu is not expected to pay significant income taxes in the next 8 years.

Power Purchase Agreement. Kaxu has a 20-year PPA with Eskom Holdings SOC Ltd., or Eskom, under a take or pay contract for the purchase of electricity up to the contracted capacity from the facility. The PPA expires in February 2035. Eskom purchases all the output of the Kaxu plant under a fixed-price formula in local currency subject to indexation to local inflation which we believe protects us from potential devaluation over the long term.

Eskom is a state-owned, limited liability company, wholly owned by the government of the Republic of South Africa. Eskom’s payment guarantees are underwritten by the South African Department of Energy, under the terms of an implementation agreement. Eskom’s credit ratings have recently worsened and is currently B- from S&P, Ba3 from Moody’s and BB+ from Fitch. The Republic of South Africa’s credit ratings are currently BB from S&P, Baa3 from Moody’s and BB+ from Fitch.

Engineering, Procurement and Construction Agreement. Certain Abengoa subsidiaries carried out the construction of Kaxu under an arm’s-length, fixed-price and date-certain engineering, procurement and construction contract. In December 2016, two water pumps failed, temporarily limiting the plant’s production until repaired. During 2017, we carried out repairs on the water pumps and the heat exchangers in the storage system. The insurance claim for repairs and loss of production of the water pumps was collected in the second quarter of 2017. The EPC contract provides a performance guarantee of 12 consecutive and uninterrupted months within the initial 24-month period, for the benefit of the project company and the financing parties. We reached an agreement with Abengoa and the lenders of the project financing agreement to extend the production guarantee until October 2018. The agreement includes an extension of the existing South African rand 570 million (approximately $45 million) letter of credit until the expiration of the new production guarantee period.

Operations & Maintenance. Kaxu entered into an O&M Agreement with Kaxu CSP O&M Company, a company owned by a subsidiary of Abengoa Solar (92%) and Kaxu Black Employee Trust, (8%) for the operation and maintenance of the Project. The O&M is for a period of 19 years from COD. The operator operates the facility in accordance with prudent utility practices, to ensure compliance with all applicable government and agency permits, licenses, approvals and PPA terms, and to assist Kaxu with the procurement of necessary support and ancillary services.

Project Level Financing. Kaxu has closed long-term financing with a lenders' group comprising local commercial banks Nedbank and RMB, local development finance institutions Industrial Development Corporation of South Africa and Development Bank of Southern Africa, as well as the International Finance Corporation for a total approximate amount of 5,860.0 million South African rand. The loan consists of senior and subordinated long-term loans payable in South African rand over an 18-year term with the cash generated by the project. The loan was initially 100% hedged through a swap with the same banks providing the financing, and the coverage progressively reduces over the life of the loan with a current effective annual interest rate of 11.44%.

As of December 31, 2017, the outstanding amount of these loans was $456 million.

The financing arrangement permits dividend distributions on a semi-annual basis after the first repayment of debt has occurred, as long as the historical and projected debt service coverage ratios are at least 1.2x. In 2017, Kaxu's debt coverage ratio did not reach the minimum threshold due to the technical problems that the plant experienced since the end of 2016, and the lenders of the project finance agreement granted a waiver to the asset.

Palmatir

Overview. Palmatir is an on-shore wind farm facility in Uruguay with nominal installed capacity of 50 MW. Palmatir has 25 wind turbines and each turbine has a nominal capacity of 2 MW. Palmatir reached COD in May 2014.

The wind farm is located in Tacuarembo, 170 miles north of the city of Montevideo. Gamesa, a global leader in the manufacture and maintenance of wind turbines, supplied the turbines from its U.S. subsidiary.

Palmatir is not expected to pay significant corporate taxes in the next 10 years due to the specific tax exemptions established by the Uruguayan government for renewable assets.

Power Purchase Agreement. Palmatir signed a PPA with UTE on September 14, 2011 for 100% of the electricity produced. UTE pays a fixed tariff under the PPA, which is denominated in U.S. dollars and will be partially adjusted in January of each year based on a formula referring to U.S. CPI and the Uruguay's Indice de Precios al Productor de Productos Nacionales and the applicable UYU/U.S. dollars exchange rate.

UTE is unrated and Uruguay has senior unsecured credit ratings of BBB- from S&P, Baa2 from Moody's and BBB from Fitch.

Operations & Maintenance. Palmatir signed an agreement with Operacion y Mantenimiento Uruguay (formerly Epartir), a subsidiary of Omega that is in turn a wholly-owned Abengoa subsidiary, for the provision of O&M services for a 20-year term. The O&M agreement covers scheduled and unscheduled turbine maintenance, a supply of spare parts, wind farm monitoring and reporting services. The O&M agreement contains customary guarantees, such as two-year guarantee and repairs. Operacion y Mantenimiento Uruguay subcontracted with the wind turbine manufacturer Gamesa for the wind turbine O&M services.

Project Level Financing. Palmatir signed a financing agreement on April 11, 2013, for a 20-year loan in two tranches in connection with the project. Each tranche is denominated in U.S. dollars. The first tranche is a $73 million loan from the U.S. Export Import Bank with a fixed interest rate of 3.11%. The second tranche is a $40 million loan from the Inter-American Development Bank with a floating interest rate of LIBOR plus 4.125%. The project hedged 80% of the floating rate loan with a swap at a rate of 2.22% with the financing bank. The combined principal balance of both tranches as of December 31, 2017 was $95 million.

Cash distributions are permissible every six months subject to a historical debt service coverage ratio for the previous twelve-month period and a projected debt service coverage ratio of at least 1.25x for the following twelve-month period.

Cadonal

Overview. Cadonal is an on-shore wind farm facility in Uruguay with nominal installed capacity of 50 MW. Cadonal has 25 wind turbines of 2 MW each. Cadonal reached COD in December 2014.

The wind farm is located in Flores, 105 miles north of the city of Montevideo. Gamesa, a global leader in the manufacture and maintenance of wind turbines, supplied the turbines.

Cadonal is not expected to pay significant corporate taxes in the next 10 years due to the specific tax exemptions established by the Uruguayan government for renewable assets.

Power Purchase Agreement. Cadonal signed a PPA with UTE on December 28, 2012, for 100% of the electricity produced. UTE pays a fixed tariff under the PPA, which is denominated in U.S. dollars and is adjusted every January considering both U.S. and Uruguay's inflation indexes and the exchange rate between Uruguayan pesos and U.S. dollars.

UTE is unrated and Uruguay has senior unsecured credit ratings of BBB- from S&P, Baa2 from Moody's and BBB from Fitch.

Operations & Maintenance. Cadonal signed an agreement with Operacion y Mantenimiento Uruguay (formerly Epartir), a subsidiary of Abengoa, for the provision of operations and maintenance services for 19 years. Although this agreement covered turbine scheduled and unscheduled maintenance, supply of spare parts, wind farm monitoring and reporting, Operacion y Mantenimiento Uruguay subcontracted the wind turbine O&M to the wind turbine manufacturer Gamesa.

Project Level Financing. On September 15, 2014, Cadonal executed an A/B loan agreement and a subordinated debt tranche. The first drawdown occurred on November 28, 2014. The A/B loan is denominated in U.S. dollars. The A tranche, with a tenor of 19.5 years, is a $40.5 million loan from Corporacion Andina de Fomento, or CAF, with a floating interest rate of LIBOR (six months) plus 3.9% for as long as CAF has access to funding from BankBankengruppe Kreditanstalt fur Wiederaufbau, or KfW, a German public law development institution, through its program for the development of certain climate-relevant projects. An interest rate swap was arranged in order to mitigate interest rate risk for the Tranche A loan, covering the 70% of the interests through a swap set at approximately 3.29% strike. The B tranche is a $40.5 million loan from DNB Bank with a floating interest rate of LIBOR (six months) plus 3.65% for as long as CAF has access to funding from KfW, with a tenor of 17.5 years. The B tranche loan was approximately 70% hedged through swap set at approximately 3.16% strike. The subordinated debt tranche was signed with CAF in the amount of $9.1 million, with a tenor of 19.5 years and a floating interest rate of LIBOR (six months) plus 6.5%. This subordinated debt tranche may be prepaid in the future at no significant cost to improve the cash generation profile.

The combined principal balance of these loans as of December 31, 2017 was $82 million.

Cash distributions are permissible every six months subject to a historical senior debt service coverage ratio for the previous twelve-month period of at least 1.20x, a total debt service coverage ratio of at least 1.10x and a projected senior debt service coverage ratio for the following twelve-month period of at least 1.10x, except in the case of the first distribution, in which case the projected senior debt service coverage ratio for the following twelve-month period must be at least 1.20x, the projected total debt service coverage for the following twelve-month period must be at least 1.10x, and both the historical senior debt coverage ratio and the historical total debt coverage ratio must be confirmed by the auditors.

Mini-hydro Peru

Mini-hydro Peru is a 4 MW mini-hydroelectric power plant located approximately 99 miles from Lima, Peru which was acquired on February 28, 2018. The plant reached COD in April 2012. It has a 20-year fixed-price concession agreement denominated in U.S. dollars with the Ministry of Energy of Peru and the price is adjusted annually in accordance with the U.S. Consumer Price Index. Peru has a long-term credit rating of BBB+ from S&P, A3 from Moody's and BBB+ from Fitch. The operation and maintenance service is provided by our in-house team. According to our estimates, Mini-hydro is not expected to pay corporate taxes in the next 10 years. The asset has a 17-year, non-recourse project financing with Inter-American Investment Corporation.

Efficient Natural Gas (previously named "conventional") Power

The following table provides an overview of our sole efficient natural gas power asset:

Asset	Location	Capacity	Currency	Offtaker	Counterparty Credit Rating(1)	COD	Contract Years Left
ACT	Mexico	300 MW	U.S. dollars(2)	Pemex	BBB+/A3/BBB+	2Q 2013	15

Notes:—

(1) Reflects the counterparty's issuer credit ratings issued by S&P, Moody's and Fitch.
(2) Payable in Mexican pesos.

ACT

Overview. ACT is a gas-fired cogeneration facility located inside the Nuevo Pemex Gas Processing Facility near the city of Villahermosa in the State of Tabasco, Mexico. It has a rated capacity of approximately 300 MW and between 550 and 800 metric tons per hour of steam. The plant includes a substation and an approximately 52-mile and 115-kilowatt transmission line. ACT reached COD on April 1, 2013. ACT Energy Mexico, S. de R.L. de C.V., or ACT Energy Mexico, owns ACT.

The ACT Plant utilizes mature and proven gas combustion turbines and heat recovery technology. Specifically, the ACT Plant utilizes two GE Power & Water "F" technology natural gas-fired combustion turbines and two Cerrey, S.A. de C.V., or Cerrey, heat recovery steam generators.

ACT is not expected to pay significant income taxes until the fifth or sixth year after our IPO, i.e., until 2019 or 2020 due to the NOLs generated during the construction phase.

Conversion Services Agreement. On September 18, 2009, ACT entered into the Pemex Conversion Services Agreement, or the Pemex CSA, with Petroleos Mexicanos, or Pemex, under which ACT is required to sell all of the plant's thermal and electrical output to Pemex. The Pemex CSA has an initial term of 19 years from the in-service date and will expire on March 31, 2033. The parties may mutually extend the Pemex CSA for an additional 20-year period. The Pemex CSA requires Pemex to supply the facility, free of charge, with the fuel and water necessary to operate ACT, and the latter has to produce electrical energy and steam requested by Pemex based on the expected levels of efficiency. The Pemex CSA is denominated in U.S. dollars. The price is fixed and will be adjusted annually, part of it according to inflation and part according to a mechanism agreed in the contract that on average over the life of the contract reflects expected inflation.

Pemex has a corporate credit rating of BBB+ by S&P, A3 by Moody's and BBB+ by Fitch.

Operations & Maintenance. GE International provides services for the maintenance, service and repair of the gas turbines as well as certain equipment, parts, materials, supplies, components, engineering support test services and inspection and repair services. In addition, NAES Mexico, S. de R.L. de C.V., or NAES, is responsible for the O&M of the ACT Plant. The O&M agreement with NAES expires upon the expiration of the Pemex CSA, although we may now cancel it with no penalty. ACT Energy Mexico pays NAES for its reimbursable costs, operating costs and a management fee.

Project Level Financing. On December 19, 2013, ACT Energy Mexico signed a $680 million senior loan agreement with a syndicate of banks led by Banco Santander, Banobras and Credit Agricole Corporate & Investment Bank. Each tranche of the loan is denominated in U.S. dollars. The financing consists of a $333 million of tranche one and a $327 million of tranche two plus an additional $20 million for the issuance of a letter of credit. After the entry of SMBC, EDC, La Caixa, Nafin and Bancomext into the financing in 2014 and subsequent to the first scheduled principal repayment, the first tranche amounted to $205.4 million and the second tranche to $450.4 million, thereby continuing to maintain the same aggregate total amount of $680 million.

The first tranche has a 10-year maturity, the second tranche has an 18-year maturity and the letter of credit may be convertible into additional principal that will be added to the first tranche. The interest rate on each tranche is a floating rate based on the three-month LIBOR plus a margin of 3.0% until December 2018, 3.5% from January 2019 to December 2023 and 3.75% from January 2024 to December 2031. The senior loan agreement requires ACT Energy Mexico to hedge the interest rate for a minimum amount of 75% of the outstanding debt amount during at least 75% of the debt term. In 2014, ACT closed a swap for an initial notional amount of $491.6 million at a weighted average rate of 3.92%.

The senior loan agreement permits cash distributions to shareholders after six months provided that the debt service coverage ratio is at least 1.20x, or at any time provided that the last four quarters had a debt service coverage ratio of at least 1.20x.

The outstanding amount of these loans as of December 31, 2017 was $579 million.

Partnerships. We own all of the shares of ACT except for two ordinary shares, which represent less than 0.01% of the total capital of ACT and which are owned by Abengoa subsidiaries.

Electric Transmission

The following table provides an overview of our electric transmission assets, each of which is operational:

Asset	Location	Length	Currency(1)	Offtaker	Counterparty Credit Rating(2)	COD	Contract Years Left
ATN	Peru	362 miles	U.S. dollars	Peru	BBB+/A3/BBB+	1Q 2011	23
ATS	Peru	569 miles	U.S. dollars	Peru	BBB+/A3/BBB+	1Q 2014	26
ATN2	Peru	81 miles	U.S. dollars	Minera Las Bambas	Not rated	2Q 2015	15
Quadra 1	Chile	49 miles	U.S. dollars	Sierra Gorda	Not rated	2Q 2014	17
Quadra 2	Chile	32 miles	U.S. dollars	Sierra Gorda	Not rated	1Q 2014	17
Palmucho	Chile	6 miles	U.S. dollars	Enel Generacion Chile	BBB+/Baa2/BBB+	4Q 2007	20

Notes:—

(1) Certain contracts denominated in U.S. dollars are payable in local currency.
(2) Reflects counterparty's issuer credit ratings issued by S&P, Moody's and Fitch.

ATN

Overview. ATN, S.A. or the ATN Project, in Peru is part of the Guaranteed Transmission System, or *Sistema Garantizado de Transmision*, or SGT, and is comprised of the following facilities:

(i) the approximately 356-mile, 220kV line from Carhuamayo-Paragsha-Conococha-Kiman Ayllu-Cajamarca Norte;

(ii) the 4.3-mile, 138kV link between the existing Huallanca substation and Kiman Ayllu substations;

(iii) the 1.9-mile, 138kV link between the 138kV Carhuamayo substation and the 220kV Carhuamayo substation;

(iv) the new Conococha and Kiman Ayllu substations; and

(v) the expansion of the Cajamarca Norte, 220kV Carhuamayo, 138kV Carhuamayo and 220kV Paragsha substations.

ATN reached COD for each line as set forth below:

Line	kV	Beginning	End	COD
1	220	Carhuamayo	Paragsha	January 11, 2011
2	220	Paragsha	Conococha	February 24, 2011
3	220	Conococha	Kiman Ayllu	December 28, 2011
4	220	Kiman Ayllu	Cajamarca Norte	June 26, 2011

Credititulos Sociedad Titulizadora S.A., or Credititulos, acts as trustee for the senior bond holders of the trust and as owner of the ATN Project.

Concession Agreement. Pursuant to the initial concession agreement, the Peruvian Ministry of Energy, on behalf of the Peruvian Government, granted ATN a concession to construct, develop, own, operate and maintain the ATN Project. The initial concession agreement became effective on May 22, 2008 and will expire 30 years after the COD of Line 1, which was achieved on January 11, 2011.

Pursuant to the initial concession agreement, ATN owns all assets that it has acquired to construct and operate the ATN Project for the duration of the concession. The ownership of these assets will revert to the Peruvian Ministry of Energy upon termination of the initial concession agreement.

The ATN Project has a 30-year, fixed-price tariff base denominated in U.S. dollars that is adjusted annually after the COD for each line in accordance with the U.S. Finished Goods Less Food and Energy Index as published by the U.S. Department of Labor. Our receipt of the tariff base is independent from the effective utilization of the transmission lines and substations related to the ATN Project. The tariff base is intended to provide the ATN Project with consistent and predictable monthly revenues sufficient to cover the ATN Project's operating costs and debt service and to earn an equity return.

Peruvian law requires the existence of a definitive concession agreement to perform electricity transmission activities where the transmission facilities cross public land or land owned by third parties. On February 20, 2010, the Peruvian Ministry of Energy executed a definitive concession agreement with ATN to transmit electricity using the transmission lines of the ATN Project. The Peruvian Ministry of Energy also approved the execution of the concession agreement between the Peruvian Ministry of Energy and ATN, which was executed on February 23, 2010, and formalized by public deed dated March 9, 2010.

ATN has generated and will generate relevant NOL carryforwards that we expect to use to offset future taxable income. According to our estimates, ATN is not expected to pay income taxes in the next 10 years.

Peru has a long-term credit rating of BBB+ from S&P, A3 from Moody's and BBB+ from Fitch.

Operations & Maintenance. ATN has an O&M agreement with Omega Peru, a subsidiary of Abengoa, specialized in O&M services for electric transmission lines across South American countries. This O&M agreement has a 27-year term with a fixed annual price adjusted yearly with the variation of the U.S. Finished Goods Less Food and Energy Index.

Project Level Financing. On September 26, 2013, ATN completed the issue of a project bond in four tranches. To implement the bond issuance, ATN created a trust holding all of the assets and economic rights arising out of the definitive concession agreement. Each tranche is denominated in U.S. dollars. The first tranche has a principal amount of $15 million with a five-year term with quarterly amortization and bears interest at a rate of 3.84375% per year. The second tranche has a principal amount of $50 million with a 15-year term with quarterly amortization and bears interest at a rate of 6.15% per year. The second tranche has a five-year grace period for principal repayment. The third tranche has a principal amount of $45 million with a 26-year term and bears interest at a rate of 7.53% per year. The third tranche has a 15-year grace period for principal repayments. The fourth tranche has a principal amount of $10 million with a 15-year term and bears interest at a rate of 6.88% per year. The fourth tranche has a 5-year grace period for principal repayments. As of December 31, 2017, $108 million in aggregate principal amount was outstanding.

Cash distributions are subject to a historical debt service coverage ratio for the last six months of at least 1.10x.

ATS

Overview. ABY Transmision Sur S.A., or ATS Project, in Peru is part of the SGT, and consists of:

i. one 500kV electric transmission line and two short 220kV electric transmission lines, which are linked to existing substations;

ii. three 500kV substations; and

iii. the expansion of three existing substations (two existing 220kV substations and one existing 550/220kV substation), through the development of new transformers, line reactors, series reactive compensation and shunt reactions in some substations.

The transmission lines span approximately 569 miles and cross over the Lima, Ica, Arequipa and Moquegua districts. The new substations are located in the district of Poroma (Marcona), Ocona and Montalvo. Abengoa Transmision Sur S.A., or ATS, owns the ATS Project. ATS reached COD on January 17, 2014.

Construction of the transmission lines and related substations required for operation of the ATS Project is complete. Pursuant to the concession agreements, the Peruvian Ministry of Energy granted ATS the right to operate the ATS Project for 30 years from achieving COD. As part of the initial concession agreement, ATS agreed to construct the Montalvo substation second bus bar, which is a strip or bar of copper, brass or aluminum that conducts electricity within an electrical system. The second bus bar was not required for operation of the ATS Project and its construction was completed in December 2014.

ATS has generated, and will generate, relevant NOL carryforwards that we expect to use to offset future taxable income. According to our estimates, ATS is not expected to pay income taxes in the next 8 years.

Concession Agreement. Pursuant to the initial concession agreement, the Peruvian Ministry of Energy, on behalf of the Peruvian Government granted ATS a concession to construct, develop, own, operate and maintain the ATS Project. The initial concession agreement became effective on July 22, 2010 and will expire 30 years after achieving COD.

Pursuant to the initial concession agreement, ATS will own all assets it has acquired to construct and operate the ATS Project for the duration of the concession. These assets will revert to the Peruvian Ministry of Energy upon termination of the initial concession agreement.

The ATS Project has a 30-year, fixed-price tariff base denominated in U.S. dollars and is adjusted annually after the COD in accordance with the U.S. Finished Goods Less Food and Energy Index as published by the U.S. Department of Labor. Our receipt of the tariff base will be independent from the effective utilization of the transmission lines and substations related to the ATS Project. The tariff base is intended to provide the ATS Project with consistent and predictable monthly revenues sufficient to cover the ATS Project's operating costs and debt service and to earn an equity return.

Peruvian law requires market participants to enter into a definitive concession agreement to perform electricity transmission activities where the transmission facilities cross public land or land owned by third parties. On June 6, 2012, the Peruvian Ministry of Energy granted ATS a definitive concession agreement to transmit electricity using the transmission lines of the ATS Project. The Peruvian Ministry of Energy approved the execution of the concession agreement between the Peruvian Ministry of Energy and ATS, which was executed on June 7, 2012 and formalized by Public Deed dated August 1, 2012.

Peru has a long-term credit rating of BBB+ from S&P, A3 from Moody's and BBB+ from Fitch.

Operations & Maintenance. Omega Peru, a wholly-owned subsidiary of Abengoa, provides O&M services for the ATS Project. Omega Peru has agreed to operate the facility in accordance with prudent utility practices, ensure compliance with all applicable government and agency permits, licenses, approvals and concession agreement terms. The O&M agreement provides a fixed fee that is adjusted annually on the anniversary of the execution of the O&M agreement to reflect the variation in the U.S. Finished Goods Less Food and Energy Index. The O&M agreement was executed for a five-year term that renews automatically for an additional five-year period until the termination of the initial concession agreement, unless either party exercises its right not to renew the O&M agreement.

Project Level Financing. On April 8, 2014, ATS issued a project bond in one tranche denominated in U.S. dollars. The project bond has a principal amount of $432 million with a 29-year term with semi-annual amortization and bears a fixed interest rate of 6.875%. The bond had a two-year grace period for principal repayment and as of December 31, 2017, $421 million was outstanding.

Cash distributions may be made every six months subject to a trailing historical debt service coverage ratio for the previous two quarters of at least 1.20x.

ATN2

Overview. ATN2, located in Peru, is part of the Complementary Transmission System, or *Sistema Complementario de Transmision*, SCT, and consists of the following facilities: (i) the approximately 130km, 220kV line from SE Cotaruse to Las Bambas; (ii) the connection to the gate of Las Bambas Substation and (iii) the expansion of the Cotaruse 220kV substation (works assigned to Consorcio Transmantaro). ATN2 reached COD in June 2015.

The Build-Own-Operate, or BOO, Contract. Pursuant to the BOO Contract executed on August 11, 2011, with Minera Las Bambas (formerly known as Xstrata Las Bambas), the project owns all assets to construct and operate the ATN2 Project.

Minera Las Bambas is owned by a partnership consisting of a China Minmetals Corporation subsidiary (62.5%), a wholly owned subsidiary of Guoxin International Investment Co. Ltd (22.5%) and CITIC Metal Co. Ltd (15.0%).

The ATN2 Project has an 18-year, fixed-price tariff base denominated in U.S. dollars, partially adjusted annually in accordance with the U.S. Finished Goods Less Food and Energy Index as published by the U.S. Department of Labor. Our receipt of the tariff base is independent from the effective utilization of the transmission lines and substations related to the ATN2 Project.

Peruvian law requires the existence of a definitive concession agreement to perform electricity transmission activities where transmission facilities cross public land or land owned by third parties. On May 31, 2014, the Peruvian Ministry of Energy granted a definitive concession agreement to the transmission lines of the ATN2 project.

ATN2 has generated and will generate relevant NOL carryforwards that we expect to use to offset future taxable income. According to our estimates, ATN2 is not expected to pay significant corporate taxes in the next 10 years.

Maintenance & Monitoring. Omega Peru, a wholly-owned subsidiary of Abengoa, provides maintenance and monitoring services for ATN2 under a 6-year term contract that is renewed every six years. Omega Peru has agreed to maintain the facility in accordance with prudent utility practices, ensure compliance with all applicable government and agency permits, licenses, approvals and concession agreement terms.

Project Level Financing. On September 28, 2011, a 15-year loan agreement was executed with Banco de Credito del Peru, or BCP, for a commitment of $50.0 million. On November 24, 2014, a new 15-year tranche was signed with BCP for $31.0 million. In addition, we have a tranche of subordinated debt that we are considering prepaying. All debt has a fixed interest rate amounting to 9.1% on a weighted average basis. The loan contemplates an amortization grace period during construction. As of December 31, 2017, the outstanding amount of the ATN2 project loan was $90 million.

Cash distributions are subject to a debt service coverage ratio of at least 1.15x.

Quadra 1 & Quadra 2

Overview. Transmisora Mejillones, or Quadra 1, is a transmission line project consisting of a 220kV double circuit transmission line that begins at the Encuentro electrical substation that is owned by Transelec and is located in the commune of Maria Elena. Quadra 1 connects to the Sierra Gorda substation owned by Sierra Gorda SCM, a mining company and is located in the commune of Sierra Gorda. The project covers approximately 49 miles. It is comprised of 232 metallic galvanized structures and 293 miles of installed conductors.

Transmisora Baquedano, or Quadra 2, is a transmission line project that provides electricity to the seawater pump stations owned by the Sierra Gorda SCM. It consists of a simple circuit 220kV electric transmission line that begins at the Angamos electrical substation owned by EE Cochrane, an electrical company, and is located in the commune of Mejillones. Quadra 2 connects to the PS1 transformer substation. This section of Quadra 2 covers approximately seven miles. This section is comprised of 29 metallic galvanized structures and has 21 miles of installed conductors. The existing pumps, which are owned by Sierra Gorda, feed from the PS1 substation and the energy is converted by a transformer from 220/110/4.8kV to 110kV to continue through a simple circuit 110kV transmission line up to the PS2 substation. This section of Quadra 2 covers approximately 25 miles. This section is comprised of 165 metallic galvanized structures and has 75 miles of installed conductors.

Abengoa Chile, began constructing Quadra 1 and Quadra 2 in September 2012. Quadra 1 reached COD in April 2014 and Quadra 2 reached COD in March 2014.

According to our estimates, Quadra 1/2 has generated and will generate relevant NOL carryforwards that we expect to use to offset future taxable income. Quadra 1/2 is not expected to pay significant corporate taxes in the next 10 years.

Concession Agreement. Both projects have concession agreements with the Sierra Gorda SCM mining company, which is owned by Sumitomo Corporation, Sumitomo Metal Mining and KGHM Polska Mietz. The concession agreement is denominated in U.S. dollars and has a 21-year term that began on the COD. The contract price is indexed mainly to the U.S. CPI.

Sierra Gorda SCM requested additional work on Quadra 2 not initially foreseen, which required an additional capital expenditure of approximately $22 million. Construction of the additional work is finished and has resulted in an increased tariff under the concession agreement with Sierra Gorda SCM.

The concession agreement grants in favor of Sierra Gorda a call option over the transmission line, exercisable at any time during the life of the contract. According to the call option, Sierra Gorda is entitled to purchase the transmission line at an agreed price and with a six-month prior written notice.

Operations and Maintenance. From COD to 2017, Abengoa Chile provided operations and maintenance service to Quadra 1 and Quadra 2. In 2017, the contracts with Abengoa Chile were terminated and new arrangements were entered into. Transelec S.A. performs operations services at Quadra 1 until March 2018. After that date, operations will be performed by Enor Chile S.A. under a 10-year contract expiring in 2027. Gas Atacama S.A. is providing operations services at Quadra 2 under a 12-year contract expiring in August 2029. Cobra Chile Servicios S.A. is performing maintenance services at Quadra 1 and Quadra 2 under 6-year contracts expiring in August 2023. The remote reading systems of both transmission lines is performed by ABB Chile S.A.

Project Level Financing. On July 6, 2012, Quadra 1 signed a financing contract for $40.2 million with Credit Agricole Corporate and Investment Bank, or CA-CIB, Corpbanca, Banco BICE and the Inter-American Investment Corporation. The loan is denominated in U.S. dollars. The term of the loan is 16 years and the loan matures on July 30, 2028. The loan has a semi-annual amortization schedule. The interest rate is a variable rate based on the six-month LIBOR plus 3.80% for the first seven years after COD and 4.0% thereafter. Quadra 1 signed an interest rate cap hedging contract with CA-CIB that covers 75% of the debt and fixed the six-month LIBOR to a maximum rate of 2.5% per year until maturity.

On November 20, 2012, Quadra 2 signed an initial financing contract for $34.4 million with CA-CIB and Corpbanca. The term of the loan is 16 years and matures on August 31, 2028 and has a semi-annual amortization schedule. The interest rate is a variable rate based on the six-month LIBOR plus 3.80% for the first seven years after COD and 4.0% thereafter. Quadra 2 signed an interest rate swap hedging contract with Corpbanca that covers 75% of the debt and fixed the six-month LIBOR to 2.5175% until maturity. Due to the additional work required by Sierra Gorda SCM, an additional debt tranche for a total of $17 million was signed in May 2014. As of December 31, 2017, $76 million in aggregate principal amount was outstanding in respect of Quadra 1 and Quadra 2.

The financing arrangements of Quadra 1 and Quadra 2 restrict cash distribution to shareholders unless a distribution test of 1.20x historical debt service coverage ratio for the previous six months is met in the case of Quadra 1, and of 1.10x historical debt service coverage ratio for the previous six months is met in the case of Quadra 2.

Palmucho

Palmucho is a short transmission line in Chile that is approximately 6 miles. It delivers energy generated by the Palmucho Plant, which is owned by Enel Generacion Chile, to the SIC. The Palmucho Plant connects to the number 2 circuit of the 220kV Ralco—Charrua transmission line at the 66/220kV Zona de Caida substation. The Palmucho project has been in operation since October 2007. Palmucho has a 14-year concession contract with Enel Generacion Chile, whereby both parties are obliged to enter into a four-year valid toll contract at the end of the term of the concession contract and the valid toll contract will be renewed for three periods of four years each until one of the parties decides not to renew. Enel Generacion Chile operates the Palmucho project and Abengoa Chile maintains the project. On October 24, 2008, Palmucho signed a long-term debt facility with Corpbanca for $7 million. The loan is denominated in U.S. dollars. The term of the loan is 13 years and matures on October 25, 2021. The loan has a quarterly amortization schedule and the outstanding balance as of December 31, 2017 was $3.7 million. Enel Generacion Chile has a senior unsecured credit rating of BBB+ from S&P, Baa2 from Moody’s and BBB+ from Fitch.

Palmucho executed an operation and maintenance agreement with Cobra in February 2017 after terminating a previous agreement.

Exchangeable Preferred Equity Investment in Abengoa Concessões Brasil Holding

In addition to the assets listed above, from our IPO until 2017 we held an exchangeable preferred equity investment in ACBH, a subsidiary holding company of Abengoa engaged in the development, construction, investment and management of contracted concessions in Brazil, comprised mostly of transmission lines, some of which were in operation and some of which were under construction.

On January 29, 2016, Abengoa informed us that several of its indirect subsidiaries of Abengoa in Brazil, including ACBH, had initiated an insolvency procedure under Brazilian law ("*reorganizaçao judiciaria*"), as a "*Pedido de processamento conjunto,*" which resulted in the consolidation of the three main subsidiaries of Abengoa in Brazil, including ACBH. In April 2016, Abengoa presented a consolidated restructuring plan in the Brazilian Court, including ACBH and two other subsidiaries. In 2016, we did not receive any preferred dividend from ACBH. Under the contracts referred to above, we retained dividends payable to Abengoa in 2016 and 2017.

In the third quarter of 2016, we signed an agreement with Abengoa relating to the ACBH preferred equity investment among other things with the following main consequences:

• Abengoa acknowledged it failed to fulfill its obligations under the agreements related to the preferred equity investment in ACBH and, as a result, we were recognized as the legal owner of the dividends that we retained from Abengoa amounting to $10.4 million in 2017, $19.0 million in 2016 and $9.0 million in the fourth quarter of 2015.

• Abengoa recognized a non-contingent credit corresponding to the guarantee provided by Abengoa regarding the preferred equity investment in ACBH, subject to restructuring. On October 25, 2016, we signed Abengoa's restructuring agreement and accepted, subject to implementation of the restructuring, to receive 30% of the amount in the form of tradable notes to be issued by Abengoa (the "Restructured Debt"). The remaining 70% was agreed to be received in the form of equity in Abengoa.

• The Restructured Debt was converted into senior status following our participation in Abengoa's issuance of asset-backed notes or New Money 1 Tradable Notes. We subsequently sold New Money 1 Tradable Notes in early April 2017.

• Since we received the Restructured Debt and Abengoa equity, we waived, as agreed, all our rights under the ACBH agreements, including our right to further retain dividends payable to Abengoa. As a result, in March 2017, we wrote off the accounting value of the ACBH instrument, which amounted to $30.5 million as of December 31, 2016. We sold most of the debt and equity instruments we received from Abengoa and we do not expect any additional value from the ACBH preferred equity investment. We no longer own any shares in ACBH.

Water

The following table presents our interests in water assets, each of which is operational:

Assets	Type	Location	Capacity	Offtaker	Currency(1)	Counterparty Credit Rating	COD	Contract Years Left
Honaine	Water	Algeria	7 M ft^3/day	Sonatrach	U.S. dollar	Not rated	3Q 2012	20
Skikda	Water	Algeria	3.5 M ft^3/day	Sonatrach	U.S. dollar	Not rated	1Q 2009	16

Note:—

(1) Payable in local currency.

Honaine

Overview. On February 3, 2015, we completed the acquisition of 25.5% of Honaine pursuant to the Abengoa ROFO Agreement.

The Honaine project is a water desalination plant located in Taffsout, Algeria, near three important cities: Oran, to the northeast, and Sidi Bel Abbes and Tlemcen, to the southeast. Myah Bahr Honaine Spa, or MBH, is the vehicle incorporated in Algeria for the purposes of owning the Honaine project. Algerian Energy Company, SPA, or AEC, owns 49% and Sociedad Anonima Depuracion y Tratamientos, or Valoriza Agua, S.L., subsidiary of Sacyr S.A., owns the remaining 25.5% of the Honaine project.

AEC is the Algerian agency in charge of delivering Algeria's large-scale desalination program. It is a joint venture set up in 2001 between the national oil and gas company, Sonatrach, and the national gas and electricity company, Sonelgaz. Each of Sonatrach and Sonelgaz owns 50% of AEC.

The technology used in the Honaine plant is currently the most commonly used in this kind of project. It consists of desalination using membranes by reverse osmosis. Honaine has a capacity of 7 M ft3 per day of desalinated water and has been in operation since July 2012. The project serves a population of 1.0 million.

Honaine has a corporate income tax exemption until 2021. After that period, in case the exemption is not extended, a claim may be made under the water purchase agreement for compensation in the tariff.

Concessions Agreement. The water purchase agreement is a U.S. dollar indexed 30-year take-or-pay contract with Sonatrach/Algerienne des Eaux, or ADE, from the date of execution, or 25-year term from COD. The tariff structure is based upon plant capacity and water production, covering variable cost (water cost plus electricity cost). Tariffs are adjusted monthly based on the indexation mechanisms that include local inflation, U.S. inflation and the exchange rate between the U.S. dollar and local currency.

Operations & Maintenance. In May 2007, MBH signed an operation and maintenance contract and a membrane and chemical products supply contract with UTE Honaine O&M (a joint venture between Abengoa Water, S.L. and Sacyr, S.A., each holding 50%).

The O&M agreement is a 30-year contract from the date of execution (or 25-year term from COD) with a fixed fee and a variable component. The fixed O&M cost covers mainly structural and staff costs. The variable O&M cost covers the chemical products, filters cost and membranes costs related to the water production.

Project Level Financing. In May 2007, MBH signed a financing agreement (as amended in November 2008 and June 2013) with Credit Populaire d'Algerie, or CPA. The final amount of the loan was $233 million and it accrues fixed-rate interest of 3.75%. The repayment of the Honaine facility agreement consists of sixty quarterly payments, ending in April 2027.

The financing arrangements permit cash distribution to shareholders once per year under certain conditions, including that the audited financials for the prior fiscal year indicate a debt service coverage ratio of at least 1.25x.

Partnerships. 51% of the plant is owned by Geida Tlemcen, which is jointly owned by us (50%) and Valoriza Agua S.L. (50%). The other 49% is held by AEC.

Skikda

Overview. On February 3, 2015, we completed the acquisition of 34.2% of Skikda pursuant to the Abengoa ROFO Agreement.

The Skikda project is a water desalination plant located in Skikda, Algeria. Skikda is located 510 km east of Algiers. Aguas de Skikda, or ADS, is the vehicle incorporated in Algeria for the purposes of owning the Skikda project. AEC owns 49% and Valoriza Agua, S.L., subsidiary of Sacyr S.A., owns the remaining 16.83% of the Skikda project.

AEC is the Algerian agency in charge of delivering Algeria's large-scale desalination program. It is a joint venture set up in 2001 between the national oil and gas company, Sonatrach, and the national gas and electricity company, Sonelgaz. Each of Sonatrach and Sonelgaz owns 50% of AEC.

The technology used in the Skikda plant is currently the most commonly used in this kind of project. It consists of the use of membranes to obtain desalinated water by reverse osmosis. Skikda has a capacity of 3.5 M ft3 per day of desalinated water and has been in operation since May 2009. The project serves a population of 0.5 million.

Skikda has a corporate income tax exemption until 2019. After that period, in case the exemption is not extended, a claim may be made under the water purchase agreement for compensation in the tariff.

Concessions Agreement. The water purchase agreement is a U.S. dollar indexed 30-year take-or-pay contract with Sonatrach/ADE from the date of execution, or 25-year term from COD. The tariff structure is based upon plant capacity and water production, covering variable cost (water cost plus electricity cost). Tariffs are adjusted monthly based on the indexation mechanisms that include local inflation, U.S. inflation and the exchange rate between the U.S. dollar and local currency.

Operations & Maintenance. In July 2005, ADS signed an operation and maintenance contract and a membrane and chemical products supply contract with UTE Geida O&M (a joint venture between Abengoa Water, S.L. holding 67%, and Sacyr, S.A., holding 33%).

The O&M agreement is a 30-year contract from the date of execution (or 25-year term from COD) with a fixed fee and a variable component. The fixed O&M cost covers mainly structural cost and staff costs. The variable O&M cost covers the chemical products, filters cost and membranes costs related to the water production.

Project Level Financing. In July 2005, ADS signed a financing agreement (as amended in May 2009) with Banque Nationale d'Algerie, or BNA. The final amount of the loan was $108.9 million and it accrues fixed-rate interest of 3.75%. The repayment of the Skikda facility agreement consists of sixty quarterly payments, ending in May 2024.

As of December 31, 2017, the outstanding amount of the Skikda project loan was $35 million.

The financing arrangements permit cash distribution to shareholders once per year under certain conditions, including that the audited financials for the prior fiscal year indicate a debt service coverage ratio of at least 1.25x.

Partnerships. 51% of the plant is owned by Geida Skikda, which is jointly owned by us (67%) and Valoriza Agua, S.L. owns (33%). The other 49% is held by AEC.

Our Growth Strategy

We intend to grow our cash available for distribution by optimizing the operations of our existing assets and acquiring new contracted revenue-generating assets in operation from AAGES, Algonquin, Abengoa, third parties and potential new future partners.

We signed an exclusive agreement with Abengoa, which we refer to as the Abengoa ROFO Agreement, which provides us with a right of first offer on any proposed sale, transfer or other disposition of any of Abengoa's contracted renewable energy, efficient natural gas power, electric transmission or water assets in operation and located in the United States, Canada, Mexico, Chile, Peru, Uruguay, Brazil, Colombia and the European Union. Under the Abengoa ROFO Agreement, Abengoa is not obligated to sell any assets to us by any date or at all. Abengoa may offer and sell to third parties assets that are not yet contracted revenue assets in operation. As a result, we do not know when, if ever, Abengoa will offer us any assets for acquisition. In addition, in the event that Abengoa elects to sell assets subject to the Abengoa ROFO Agreement, Abengoa will not be required to accept any offer we make for any such asset under the Abengoa ROFO Agreement. See "Item 7.B—Related Party Transactions—Abengoa Right of First Offer" for more details.

In addition, on March 5, 2018 we entered into a ROFO agreement with AAGES, which we refer to as the AAGES ROFO Agreement that will come into effect upon completion of the Share Sale, for which all conditions precedent have been satisfied and for which the parties have commenced the process for the transfer of our shares, which we expect to close in the upcoming days, AAGES is the joint venture formed by Algonquin and Abengoa to develop and invest renewable energy and water assets. The AAGES ROFO Agreement provides us with a right of first offer on any proposed sale, transfer or other disposition of any of AAGES' ROFO Assets. Under the AAGES ROFO Agreement, AAGES is not obligated to sell any asset to us by any date or at all. As a result, we do not know when, if ever, AAGES will offer us any assets for acquisition. In addition, if AAGES elects to sell assets subject to the AAGES ROFO Agreement, AAGES will not be required to accept any offer we make for any such asset. See "Item 7.B—Related Party Transactions—AAGES Right of First Offer" for more details.

In addition, we have a ROFO agreement with Abengoa Projects Warehouse 1, LLP, or APW-1, mirroring the ROFO agreement we have with Abengoa. APW-1 is an investment vehicle initially created by Abengoa as a joint venture with EIG and currently fully owned by EIG. Although this ROFO is in place, we cannot assure that it will survive the changes that APW-1 has experienced or will experience.

In general, we expect to acquire only assets that are developed and operational. We intend to use the following investment guidelines in evaluating prospective acquisitions in order to successfully execute our accretive growth strategy:

- high quality offtakers, with long-term contracted revenue;
- project financing in place at each project;
- operations and maintenance contract in place at each project;
- management and operational systems and processes at an adequate level;
- focus on regions and countries that provide an optimal balance between growth opportunities and security and risk considerations, including the United States, Canada, Mexico, Chile, Peru, Uruguay, Colombia and the European Union; and
- preference for U.S. dollar-denominated revenues.

Under the Abengoa ROFO Agreement, if Abengoa offers an asset to us, we will have 60 days to complete due diligence and negotiate the acquisition of the asset. If we do not agree to purchase the applicable asset after such period, Abengoa will be free to pursue the sale with other potential buyers. Under the Abengoa ROFO Agreement, Abengoa will not be obligated to sell any assets to us by any date or at all. As a result, we do not know when, if ever, Abengoa will offer any assets for acquisition. In addition, in the event that Abengoa elects to sell assets, Abengoa will not be required to accept any offer we make for any such asset. Abengoa also may, following the completion of good-faith negotiations with us during the 60-day period mentioned above, choose to sell assets to a third party or not to sell the assets at all. However, if we do not reach an agreement, any sale to a third party within 30 months following such 60-day period must be on terms and conditions generally no less favorable to Abengoa than those offered to us. After such 30-month period, the asset will cease to be an asset subject to the Abengoa ROFO Agreement. In addition, we are required to pay Abengoa a fee of 1% of the equity purchase price of any asset that we acquire as consideration for Abengoa granting us the right of first offer.

Abengoa may enter into agreements with other companies with the objective of jointly financing the construction of new projects consisting of concessional assets which are included in Abengoa's current or future portfolio. Pursuant to the terms of the Abengoa ROFO Agreement, we expect that any investing vehicle created by Abengoa and a potential partner with this purpose will sign the ROFO agreements in the same terms of Abengoa.

Our agreements with Abengoa do not prohibit Abengoa from acquiring or operating contracted assets that fulfill our principles or selling any such assets prior to operation to third parties. See "Item 3.D—Risk Factors—Risks Related to Our Relationship with Abengoa" for further information.

Under the AAGES ROFO Agreement, if AAGES offers an asset to us, we will have 60 days to complete due diligence and negotiate the acquisition of the asset. If we do not agree to purchase the applicable asset after such period, AAGES will be free to pursue the sale with other potential buyers. Under the AAGES ROFO Agreement, AAGES will not be obligated to sell any assets to us by any date or at all. As a result, we do not know when, if ever, AAGES will offer any assets for acquisition. In addition, if AAGES elects to sell assets, AAGES will not be required to accept any offer we make for any such asset. AAGES also may, following the completion of good-faith negotiations with us during the 60-day period mentioned above, choose to sell assets to a third party or not to sell the assets at all. However, if we do not reach an agreement, any sale to a third party within 30 months following such 60-day period must be at a price of at least 105% of the price they offered to us for assets located outside Canada and US, and in general on terms and conditions generally no less favorable to AAGES than those offered to us. For U.S. or Canadian assets the purchase price must not be less than 100% of the last purchase price we offered during the negotiation period. After such 30-month period, the asset will cease to be an asset subject to the AAGES ROFO Agreement.

In addition, we plan to sign agreements with other developers or asset owners or enter into partnerships with such developers or asset owners in order to acquire assets in operation or to invest directly or through investment vehicles in assets under development, ensuring that such investments are always a small part of our total investments.

Finally, we also expect to acquire assets from third parties leveraging the local presence and network we have in the geographies and sectors in which we operate.

We made the following acquisitions from Abengoa and third parties since our IPO in June 2014:

First Dropdown Assets

On November 18, 2014, we completed the acquisition of a 74% stake in Solacor 1/2, a 100 MW solar power plant in Spain; on December 4, 2014, we completed the acquisition of PS10/20, a 100 MW solar power complex in Spain; and on December 29, 2014, we completed the acquisition of Cadonal, an on-shore wind farm located in Uruguay with a capacity of 50 MW. See "Item 4.B—Business Overview—Our Operations—Renewable Energy" for a description of such assets. The total aggregate consideration for the First Dropdown Assets was $312 million (which consideration was determined in part by converting the portion of the purchase price of Solacor 1/2 and PS10/20 denominated in euros into U.S. dollars based on the exchange rate on the date on which the payment was made). The First Dropdown Assets were financed with the proceeds of the 2019 Notes and with a portion of the proceeds of the Revolving Credit Facility. See "Item 5.B—Liquidity and Capital Resources—Financing Arrangements—2019 Notes" and "Item 5.B—Liquidity and Capital Resources—Financing Arrangements—Revolving Credit Facility."

Second Dropdown Assets

On February 3, 2015, we completed the acquisition of a 25.5% stake in Honaine and a 34.2% stake in Skikda from Abengoa under the Abengoa ROFO Agreement. Honaine and Skikda are two water desalination plants in Algeria with an aggregate capacity of 10.5 M ft3 per day. Revenues of these assets are indexed to U.S. dollars and payable in local currency. On February 23, 2015, we completed the acquisition of a 29.6% stake in Helioenergy 1/2, a 100 MW solar complex located in Spain. See “Item 4.B—Business Overview—Our Operations—Renewable Energy” for a description of such assets. The total aggregate consideration for the Second Dropdown Assets was $94 million and was mainly financed with a portion of the proceeds of the Revolving Credit Facility. See “Item 5.B—Liquidity and Capital Resources—Financing Arrangements—Revolving Credit Facility.”

Third Dropdown Assets

On May 13, 2015, we completed the acquisition of Helios 1/2, a 100 MW solar complex located in Spain. On May 14, 2015, we completed the acquisition of Solnova 1/3/4, a 150 MW solar complex located in Spain. On May 25, 2015, we completed the acquisition of the remaining 70.4% stake in Helioenergy 1/2, a 100 MW solar complex in Spain. On July 30, 2015, we completed the acquisition of Kaxu, a 100 MW solar plant in South Africa. See “Item 4.B—Business Overview—Our Operations—Renewable Energy” for a description of such assets. The total aggregate consideration for the Third Dropdown Assets was $682 million and was mainly financed with the proceeds of a capital increase completed in May 2015. See “Item 5.B—Liquidity and Capital Resources.”

Fourth Dropdown Assets

On June 25, 2015, we completed the acquisition of ATN2, an 81-mile transmission line in Peru from Abengoa and Sigma, a third-party financial investor in ATN2. On September 30, 2015, we completed the acquisition of Solaben 1/6, a 100 MW solar complex in Spain. These assets were acquired from Abengoa under the Abengoa ROFO Agreement. See “Item 4.B—Business Overview—Our Operations—Renewable Energy” for a description of such assets. In addition, on January 7, 2016, we completed the acquisition from JGC of a 13% in Solacor 1/2, a 100 MW solar complex in Spain where we already owned a 74% stake. The total aggregate consideration for the Fourth Dropdown Assets was $378 million and was mainly financed with Tranche B of our Revolving Credit Facility. See “Item 5.B—Liquidity and Capital Resources—Financing Arrangements—Revolving Credit Facility.”

Subsequent acquisitions

On August 3, 2016, we completed the acquisition of an 80% stake in Seville PV from Abengoa, a 1 MW solar photovoltaic plant in Spain.

On February 28, 2017, we completed the acquisition of a 12.5% interest in a 114-mile transmission line in the U.S. from Abengoa at cost. The asset will receive a Federal Energy Regulatory Commission (“FERC”) regulated rate of return, and is currently under development, with COD expected in 2020. We expect our total investment to be up to $10 million in the coming three years, including the initial investment made at cost.

On February 28, 2018, we completed the acquisition of a 4 MW mini-hydroelectric power plant in Peru for a cash consideration of $9 million. The plant reached COD in 2012. It has a fixed-price concession agreement denominated in U.S. dollars with the Ministry of Energy of Peru and the price is adjusted annually in accordance with the U.S. Consumer Price Index.

Customers and Contracts

We derive our revenue from selling electricity, electric transmission capacity and desalination capacity. Our customers are mainly comprised of governments and electrical utilities, the latter with which we typically have entered into PPAs. We also employ concession contracts, typically ranging from 20 to 30 years. See the description of each asset under “Item 4.B—Business Overview—Our Operations” for more detail on each concession contract.

Our main contracts in our business also include the project finance contracts with banks or financial institutions and the operation and maintenance contracts of each of our assets. See description of financing and operation and maintenance contracts under “Item 4.B—Business Overview—Our Operations.”

Additionally, we have entered into a ROFO agreement, a Financial Support Agreement and other agreements with Abengoa as well as a ROFO agreement with AAGES and Algonquin. See “Item 7.B—Related Party Transactions” for more detail on these contracts.

Competition

Renewable energy, efficient natural gas power and electric transmission are all capital-intensive and significantly commodity-driven businesses with numerous industry participants. We compete based on the location of our assets and ownership of portfolios of assets in various countries and regions; however, because our assets typically have 20- to 30-year contracts, competition with other asset operations is limited until the expiration of the PPAs. Power generation and transmission are highly regulated businesses in each country in which we operate and are currently highly fragmented and have a diverse industry structure. Our competitors have a wide variety of capabilities and resources. Our competitors include, among others, regulated utilities and transmission companies, other independent power producers and power marketers or trading companies and state-owned monopolies.

Intellectual Property

In general, the construction or other agreements in each asset allow us to use the technology and intellectual property of suppliers. We own the Atlantica Yield name and the www.atlanticayield.com domain.

Regulatory and Environmental Matters

See “Item 4.B—Business Overview—Regulation.”

Insurance

We maintain the types and amounts of insurance coverage that we believe are consistent with customary industry practices in the jurisdictions in which we operate. Our insurance policies cover employee-related accidents and injuries, property damage, machinery breakdowns, fixed assets, facilities and liability deriving from our activities, including environmental liability. We maintain business interruption insurance for interruptions resulting from incidents covered by insurance policies, with a customary deductible period. Our insurance policies also cover directors’ and officers’ liability and third-party insurance. We cannot assure you, however, that our insurance coverage will adequately protect us from all risks that may arise or in amounts sufficient to prevent any material loss or that premiums will not increase in the future and that insurers will not change the terms of the policies in the future, including changes in deductible costs and periods. See “Item 3.D—Risk Factors—Risks Related to Our Business and the Markets in Which We Operate—Our insurance may be insufficient to cover relevant risks and the cost of our insurance may increase.”

Seasonality

Our operating results and cash flows can be significantly affected by weather in some of our most relevant projects, such as the solar power plants. We expect to derive a majority of our annual revenues in the months of May through September, when solar generation is the highest in the majority of our markets and when some of our offtake arrangements provide for higher payments to us.

Properties

See “Item 4.B—Business Overview—Our Operations.”

Legal Proceedings

On October 17, 2016, ACT received a request for arbitration from the International Court of Arbitration of the International Chamber of Commerce presented by Pemex. Pemex is requesting compensation for damages caused by a fire that occurred in their facilities during the construction of the ACT cogeneration plant in December 2012, for a total amount of approximately $20 million. On July 5, 2017, Seguros Inbursa, the insurer of Pemex, joined as a second claimant in the process. In the event that the arbitration results in a negative outcome, we expect these damages to be covered by the existing insurance policy. As a result, we do not expect this proceeding to have a material adverse effect on our financial position, cash flows or results of operations.

A number of Abengoa's subcontractors and insurance companies that issued bonds covering Abengoa's obligations under such contracts in the United States have included some of our non-recourse subsidiaries in the U.S. as co-defendants in claims against Abengoa. Generally, our subsidiaries have been dismissed as defendants at early stages of the processes but there remain pending cases including Arb Inc. with a potential total claim of approximately $33 million and a group of insurance companies that have addressed to a number of Abengoa's subsidiaries and to Solana (Arizona Solar One) a potential claim for Abengoa related losses of approximately $20 million that could increase, according to the insurance companies, up to a maximum of up to approximately $200 million if all their exposure resulted in losses. Based on our assessment with information currently available, we do not expect these proceedings, individually or in the aggregate, to have a material adverse effect on our financial position, cash flows or results of operations.

We are not a party to any other significant legal proceeding other than legal proceedings arising in the ordinary course of our business. We are party to various administrative and regulatory proceedings that have arisen in the ordinary course of business. While we do not expect these proceedings, either individually or in the aggregate, to have a material adverse effect on our financial position or results of operations, because of the nature of these proceedings we are not able to predict their ultimate outcomes, some of which may be unfavorable to us.

Regulation

Overview

We operate in a significant number of highly regulated markets. The degree of regulation to which our activities are subject varies by country. In a number of the countries in which we operate, regulation is carried out mainly by national regulatory authorities. In others, such as the United States and, to a certain degree, Spain, there are various additional layers of regulation at the state, regional and/or local level. In countries with these additional layers of regulatory agencies, the scope, nature and extent of regulation may differ among the various states, regions and/or localities.

While we believe the requisite authorizations, permits and approvals for our assets have been obtained and that our activities are operated in substantial compliance with applicable laws and regulations, we remain subject to a varied and complex body of laws and regulations that both public officials and private parties may seek to enforce. The following is a description of the primary industry-related regulations applicable to our assets that are currently in force in the principal markets in which we operate.

Regulation in the United States

In the United States, our electricity generation project companies are subject to extensive federal, state and local laws and regulations that govern the development, ownership, business organization and operation of power generation facilities. The federal government regulates wholesale sales, operation and interstate transmission of electric power through FERC and through other federal agencies, and certain environmental, health and safety matters. State and local governments regulate the siting, permitting, construction and operation of power generation facilities, the retail sale of electricity and certain other environmental, health, safety and permitting matters.

United States Federal Regulation of the Power Generation Facilities and Electric Transmission

The United States federal government regulates the wholesale sale of electric power and the transmission of electricity in interstate commerce through the FERC, which draws its jurisdiction from the FPA, as amended, and from other federal legislation such as the Public Utility Regulatory Policies Act of 1978, or PURPA, the Energy Policy Act of 1992, and the Energy Policy Act of 2005, or EPACT 2005. EPACT 2005 repealed the Public Utility Holding Company Act of 1935 and replaced it with the Public Utility Holding Company Act of 2005, or PUHCA.

Federal Regulation of Electricity Generators

The FPA provides FERC with exclusive ratemaking jurisdiction over all public utilities that engage in wholesale sales of electricity and/or the transmission of electricity in interstate commerce. The owners of renewable energy facilities selling at wholesale are therefore generally subject to FERC's ratemaking jurisdiction. FERC may authorize a public utility to make wholesale sales of electric energy and related products at negotiated or market-based rates if the public utility can demonstrate that it does not have, or that it has adequately mitigated, horizontal and vertical market power and that it cannot otherwise erect barriers to market entry. Entities granted market-based rate approval face ongoing filing and compliance requirements. Failure to comply with such requirements may result in a revocation of market-based rate authority, disgorgement of profits, civil penalties or other remedies that FERC finds appropriate based on the specific underlying facts and circumstances. In granting market-based rate approval to a wholesale generator, FERC also typically grants blanket authorizations under Section 204 of the FPA and FERC's regulations for the issuance of securities and the assumption of debt liabilities.

If the criteria for market-based rate authority are not met, FERC has the authority to impose conditions on the exercise of market rate authority that are designed to mitigate market power or to withhold or rescind market-based rate authority altogether and require sales to be made based on cost-of-service rates, which could in either case result in a reduction in rates. FERC also has the authority to assess substantial civil penalties (up to $1.0 million per day per violation) for failure to comply with tariff provisions or the requirements of the FPA.

FERC approval under the FPA may be required prior to a change in ownership or control of voting interests, directly or through one or more subsidiaries, in any public utility (including one of our U.S. project companies) or any public utility assets. FERC approval may also be required for individuals to serve as common officers or directors of public utilities or of a public utility and certain other companies that provide financing or equipment to public utilities.

FERC also implements the requirements of PUHCA applicable to "holding companies" having direct or indirect voting interests of 10% or more in companies that (among other activities) own or operate facilities used for the generation of electricity for sale, which includes renewable energy facilities. PUHCA imposes certain record-keeping, reporting and accounting obligations on such holding companies and certain of their affiliates. However, holding companies that own only exempt wholesale generators, or EWGs, foreign utility companies, and certain qualifying facilities under PURPA are exempt from the federal access to books and records provisions of PUHCA. EWGs are owners or operators of electric generation facilities (including producers of renewable energy, such as solar projects) that are engaged exclusively in the business of owning and/or operating generating facilities and selling electricity at wholesale. An EWG cannot make retail sales of electricity, may only own or operate the limited interconnection facilities necessary to connect its generating facility to the grid, and faces restrictions in transacting business with affiliated regulated utilities.

Regulation of Electricity Sales

Electricity transactions in the United States may be bilateral in nature, whereby two parties contract for the sale and purchase of electricity, subject to various governmental approval processes or guidelines that may apply to the contract, or they may take place within a single, centralized clearing market for purchases and sales of energy, electric generating capacity and ancillary services. Given the limited interconnections between power transmission systems in the United States and differences among market rules, regional markets have formed as part of the power transmission systems operated by regional transmission organizations, or RTOs, or independent system operators, or ISOs, in places such as California, the Midwest, New York, Texas, the Mid-Atlantic region and New England.

Federal Reliability Standards

EPACT 2005 amended the FPA to grant FERC jurisdiction over all users, owners and operators of the bulk power system for the purpose of enforcing compliance with certain standards for the reliable operation of the bulk power system. Pursuant to its authority under the FPA, FERC certified the North American Electric Reliability Corporation, or NERC, as the entity responsible for developing reliability standards, submitting them to FERC for approval, and overseeing and enforcing compliance with them, subject in each case to FERC review. NERC, in turn, has delegated certain monitoring and enforcement powers to regional reliability organizations. Users, owners, and operators of the bulk power system meeting certain materiality thresholds are required to register with the NERC compliance registry and comply with FERC-approved reliability standards.

In the western United States, NERC has a delegation agreement with the Western Electricity Coordinating Council, or WECC, whose service territory extends from Canada to Mexico and includes the provinces of Alberta and British Columbia, the northern portion of Baja California, Mexico, and all or portions of the 14 western states in between. WECC is the regional entity responsible for coordinating, promoting and enforcing bulk power system reliability in its service territory. Any entity that owns, operates or uses any portion of the bulk power system must comply with NERC or WECC's mandatory reliability standards. Failure to comply with these mandatory reliability standards may subject a user, owner or operator to sanctions, including substantial monetary penalties, which range from $1,000 to $1 million per day per violation for the most severe cases, where companies show negligence and lack evidence of adequate compliance.

Federal Environmental Regulation, Permitting and Compliance

Construction and operation of power generation facilities, including solar power plants, and the generation and electric transmission of renewable energy from such facilities are subject to environmental regulation at the federal, state and local level. State and local regulatory processes are discussed separately in a subsequent section. At the federal level, environmental laws and regulations typically require a lengthy and complex process for obtaining licenses, permits and approvals prior to construction, operation or modification of a generation project or electric transmission facilities. Prior to development, permitting authorities may require that project developers consider and address, among other things, the impact on water resources and water quality, endangered species and other biological resources, compatibility with existing land uses and zoning, agricultural resources, archaeological, paleontological, recreational and cultural considerations, environmental justice and cumulative and visual impacts. In an effort to identify and minimize the potential impacts to these resources, power generation facilities may be required to comply with a myriad of federal regulatory programs and applicable federal permits under the National Environmental Policy Act, or NEPA, the Endangered Species Act, the Clean Water Act, the National Historic Preservation Act, the Resource Conservation and Recovery Act, the Comprehensive Environmental Response, Compensation, and Liability Act, the Environmental Protection and Community Right-to-Know Act and the National Wilderness Preservation Act, among other federal laws.

In addition, various federal environmental, health and safety regulations applicable during the construction phase are also applicable to the operational phase of power generation facilities. During the operational phase, obtaining certain federal permits or federal approval of certain operating documents (e.g., O&M plans, the spill prevention, control and countermeasure plan, and an emergency and preparedness response plan), as well as maintaining strict compliance with such permits or operating documents, is mandatory. Failure to maintain compliance may result in the revocation of any applicable permit or authorization, civil and criminal charges and fines or potentially the closure of the plant.

U.S. Federal Income Tax Reform

On December 22, 2017, the TCJA was signed into law. The centerpiece of the TCJA is the permanent reduction in the corporate income tax rate to 21% from 35% under prior law. Among other changes, the TCJA imposes new limitations on interest deductions, imposes a new excise tax on certain payments made to non-U.S. related parties, changes the rules relating to the use of NOLs and temporarily changes the rules relating to depreciation deductions.

The TCJA limits net business interest expense deductions to 30% of adjusted taxable income. For 2018 through 2021, this amount generally approximates to earnings before interest, taxes, depreciation and amortization (i.e., EBITDA). For tax years beginning after December 31, 2021, adjusted taxable income is determined by adding back only interest and taxes (i.e., it generally will approximate EBIT). The amount of interest paid or accrued that exceeds 30% of adjusted taxable income is treated as excess interest expense and may be carried forward to future taxable years. TCJA does not provide any grandfathering for debt that existed prior to enactment. This new limitation replaces the earnings stripping rules under Section 163(j) of the IRC that applied to interest paid on certain debt to or guaranteed by a related party.

The TCJA also imposes an excise tax on certain deductible payments, including interest, made by certain U.S. corporations to a non-U.S. related party to the extent the payment is not subject to U.S. withholding tax (the "BEAT"). The BEAT payable for any taxable year is an amount equal to the excess, if any, of (i) 10% (5% in 2018 and 12.5% after 2025) of the taxable income of the taxpayer calculated without regard to any deductions allowed for base erosion payments for the taxable year and certain net operating losses attributable to base erosion payments, over (ii) the taxpayer's regular tax liability reduced by certain tax credits. The BEAT only applies to corporations with average annual gross receipts of at least $500M and that have made outbound deductible payments that constitute at least 3% of the aggregate amount of certain deductions allowed for the taxable year (both determined on a groupwide basis).

NOLs generated on or before December 31, 2017 can generally be carried back two years and carried forward up to twenty years and can be applied to offset 100% of taxable income in such years. Under the TCJA, however, federal NOLs incurred in 2018 and in future years may be carried forward indefinitely but may not be carried back. Additionally, the deductibility of such federal NOLs is limited to 80% of taxable income in such years. The rules regarding "ownership changes" under Section 382 of the IRC were left unchanged.

Under prior law, the cost of property was required to be capitalized and recovered over time through annual deductions for depreciation or amortization. Tangible property generally was depreciated under MACRS. Most of the equipment used in solar power projects, such as Solana and Mojave, qualifies for five-year depreciation under MACRS. Additionally, some equipment used in solar power projects qualified for bonus depreciation if it was equipment placed in service prior to 2020 (with a phase down for property placed in service after 2017). The TCJA temporarily extends and modifies the additional first year depreciation deduction. Under the TCJA, generally, bonus depreciation is 100% for property acquired and placed in service after September 27, 2017 and before 2026 (with a phase down for property placed in service after 2022).

U.S. Federal Considerations for Renewable Energy Generation Facilities

The United States provides various federal, state and local tax incentives to stimulate investment in renewable energy generation capacity, including solar power. These tax incentives are subject to change and, possibly, elimination in the future. Certain U.S. federal income tax incentives are described below.

Section 1603 U.S. Treasury Grant Program

In lieu of claiming certain U.S. federal income tax credits, in particular, the ITC, owners of eligible solar energy property were eligible for a period of time to receive a cash grant from U.S. Treasury equal to 30% of the tax basis of the eligible property. Among other requirements, to be eligible for a 1603 Cash Grant, the eligible property must have been placed in service in 2009, 2010 or 2011 or, for property not placed in service during that period, the construction of the specified energy property must have begun after December 31, 2008 and before January 1, 2012. In addition, eligible solar energy property must be placed in service by January 1, 2017. Applicants who began construction after December 31, 2008 and before January 1, 2012, but who did not place the eligible solar energy property in service prior to October 1, 2012, were required to file a preliminary 1603 Cash Grant application prior to October 1, 2012. These applicants are further required to file a final or "converted" 1603 Cash Grant application no later than 180 days after the eligible solar energy property is placed in service. The preliminary 1603 Cash Grant application for Solana was filed in September 2012, and the final 1603 Cash Grant application for Solana was filed on November 14, 2013 with additional information provided to the U.S. Treasury in 2014. A final award from the U.S. Treasury was made as of October 2014. The preliminary 1603 Cash Grant application for Mojave was filed on September 14, 2012. Mojave reached COD in December 2014, and a final 1603 Cash Grant application was filed on February 5, 2015. A final award from the U.S. Treasury was made to Mojave as of September 2015.

Under the 1603 Cash Grant, certain persons, "disqualified persons," are ineligible to receive the 1603 Cash Grant and are prohibited from owning a direct or indirect interest in otherwise 1603 Cash Grant-eligible solar energy property, unless the indirect interest is held through an entity taxable as a C-corporation for U.S. federal income tax purposes. 1603 Cash Grants are subject to recapture during the five-year period beginning on the date the eligible solar energy property is placed in service. The amount of the 1603 Cash Grant subject to recapture decreases ratably over the five-year recapture period. Among other events, failure of the eligible property to be used for its intended purpose or the direct or indirect transfer to a disqualified person (as described above) will cause recapture of the 1603 Cash Grant. Portions of the Solana and Mojave Cash Grant awards remain subject to this potential recapture.

Federal Loan Guarantee Program

The DOE, in an effort to promote the rapid deployment of renewable energy and electric power transmission projects, was authorized to grant guarantees with respect to certain loans to renewable energy projects and related manufacturing facilities and electric power transmission projects under Section 1703 of EPACT 2005. Previously, the DOE also granted guarantees with respect to certain loans made under Section 1705 of EPACT 2005. In order to have qualified for the Section 1705 program, physical construction must have commenced at the primary site of the project on or before September 30, 2011. NEPA review must have been completed prior to the issuance of a loan guarantee. In May 2011, the Section 1705 program expired by statute, and the DOE announced that it would no longer accept new applications under that program. On September 30, 2011, the Section 1705 loan guarantee program closed with no further loan guarantees to be issued. The DOE has also closed the Section 1703 loan guarantee program for solar assets, although it is still open for other technologies.

The senior debt for Solana and Mojave was guaranteed by the DOE pursuant to the Section 1705 loan guarantee program.

State and Local Regulation of the Electricity Industry in the United States

State regulatory agencies in the United States have jurisdiction over the rates and terms of electricity service to retail customers. Regulated investor-owned utilities often must obtain state approval for the contracts through which they purchase electricity, including renewable energy, if they seek to pass along the costs of these contracts to their retail ratepayers. Municipal utilities and electric cooperatives are typically governed on these matters by their city councils or elected boards of directors. Different states apply different standards for determining acceptable prices for utility procurement contracts, including PPAs. Our electricity generation project companies operate in Arizona and California. Information about the regulatory frameworks in Arizona and California is provided below.

United States State-Level Incentives

In addition to federal legislation, many states have enacted legislation, principally in the form of renewable portfolio standards, or RPS, which generally require electric utilities to generate or purchase a certain percentage of their electricity supplied to consumers from renewable resources. In certain states, it is not only mandatory to meet these percentages from renewable resources, which in general are on the increase, but also electric utilities may be required to generate or purchase a percentage of their electricity supplied to consumers from specific renewable energy technologies, including solar technology. Depending upon the state, various certifications, permits, contracts and approvals may be required in order for a project to qualify for particular RPS programs. Some states, for example, require that only renewable energy generated in-state counts towards the RPS. According to the Database of State Incentives for Renewable Energy, as of August 2014, 49 states and United States territories have adopted some type of RPS standards. Although there is currently no federal RPS program, there have been proposals to create a federal RPS standard for renewable energy.

Renewable Energy Certificates, or RECs, are typically used in conjunction with RPS programs as tradable certificates demonstrating that a certain number of kWh have been generated from renewable resources. Under many RPS programs, a utility may generally demonstrate, through its ownership of RECs, that it has supported an amount of renewable energy generation equal to its state-mandated RPS percentage. The sale of RECs can represent a significant additional revenue stream for renewable energy generators. In RPS states where a liquid REC market does not exist, renewable energy can be bought or sold through "bundled" PPAs, where the PPA price includes the price for renewable energy attributes. Some states require that RECs and the associated electricity be purchased together in order to count towards the RPS. In states that do not have RPS requirements, certain entities buy RECs voluntarily. These RECs generally have lower prices than RECs that are used to meet RPS obligations. The price of RECs can vary significantly, depending on their availability, which in turn depends upon the amount of renewable generation that has been put in service in a state that has implemented RPS requirements. In some states, the number of successful projects has generated more RECs than required to meet the applicable RPS requirements for a given year or years, leading to steep drops in the market price for RECs. Additionally, demand for RECs can be driven by requirements (such as those imposed under the California Environmental Quality Act) that development projects mitigate potential significant GHG impacts identified in connection with environmental clearances.

Effective October 2015, California enacted legislation that increases its existing RPS to 50% by 2030 for publicly-owned and investor-owned utilities, or IOUs. Arizona set an RPS of 15% by 2025, with 30% of the RPS to be met from distributed generation.

Other incentives that states and localities have adopted to encourage the development of renewable resources include property and state tax exemptions and abatements, state grants, and rebate programs. In addition, a number of states collect electricity surcharges on residential and commercial users and through public benefit funds reinvest some of these funds in renewable energy projects. California offered a property tax incentive for certain solar energy systems installed between January 1, 1999 and December 31, 2016. The Arizona Department of Revenue provides a corporate tax credit based on production for solar, wind, or biomass systems that are 5 MW or larger and are installed on or after December 31, 2010 and before January 1, 2021.

Solar generation may also be incentivized by state GHG emission reduction measures, such as California's cap and trade scheme, which caps and reduces GHG emissions. The California cap and trade program went into effect with respect to the electricity and other sectors starting in 2013.

Arizona

Regulation of Retail Electricity Service in Arizona

The Arizona Corporation Commission, or ACC, has complete and exclusive jurisdiction over the rates and terms under which regulated utilities may provide electricity service to retail customers in Arizona. Under the Arizona Constitution, the ACC has unilateral authority over all utility regulation, including electric and natural gas utilities. The ACC also oversees all rate cases for its jurisdictional utilities, and as such has oversight of renewable energy procurement contracts by regulated electric utilities. Under Arizona's Renewable Energy Standard & Tariff, or REST, regulated electric utilities must supply an increasing percentage of their retail electric energy sales from eligible renewable resources, including solar, wind, biomass, biogas and geothermal technologies. The renewable energy requirement is 8% of retail electric sales in 2018 and increases annually until it reaches 15% in 2025.

Unlike many other state regulatory commissions, the ACC does not approve PPAs executed by regulated utilities, nor does it issue rulings of "prudency" regarding PPAs. This practice leaves a utility somewhat at risk of recovering its costs until a successful rate case finding is rendered by the ACC. Rate recovery requests may not be filed until the utility begins to make actual expenditures for power procurement. In the case of Solana, however, the power purchaser, Arizona Public Service Company, or APS, voluntarily sought a hearing before the ACC to request its informal opinion of the prudency of the Solana PPA. After ACC staff conducted an analysis of the costs and benefits of Solana to Arizona ratepayers, it recommended to the ACC commissioners that the PPA should be deemed "a reasonable means" by which APS could meet its requirements under the REST. The ACC affirmed the staff's recommendation on September 30, 2008, thereby providing greater assurance of APS's successful rate recovery request.

Performance and Operational Provisions of Solana's PPA

The PPA executed between APS and Solana's project company, Arizona Solar, contains provisions related to guarantees of performance (e.g., provision of minimum annual renewable energy certificate (REC) eligible energy quantities to APS). The provisions are largely intended to protect APS' ability to meet its mandatory requirements under the REST, and to prevent APS from having to procure REC eligible power elsewhere at an unknown, and possibly higher, cost than the PPA price.

Siting and Construction of New Power Generation Facilities in Arizona

The Arizona Power Plant & Transmission Line Siting Committee, or Siting Committee, oversees utility and private developer applications to build power plants (of 100 MW or more) or transmission projects (of 115,000 volts or more) within Arizona. The Siting Committee holds public meetings and evidentiary hearings to determine whether a proposed generation or transmission project is compatible with the preservation of the state's environmental protection interests, and if the finding is affirmative, makes a recommendation to the ACC to grant a Certificate of Environmental Compatibility, to the applicant. The ACC then has authority to approve, decline or modify the Siting Committee's recommendation.

The ACC granted Certificates of Environmental Compatibility to Solana on December 11, 2008, for both the 280 MW solar generation project and its associated 20.8-mile, 230 kilovolt transmission line. Both the generation facility and transmission line Certificates of Environmental Compatibility contain obligatory conditions and stipulations, none of which could present a risk to Solana during the operational phase.

Other Arizona Permitting and Compliance Frameworks

Various state and county regulations, mostly related to the environment and public health and safety, are applicable during the operational phase of a solar power plant located in Maricopa County, Arizona. Such regulations include the Arizona Aquifer Water Quality Standards and Aquifer Protection Permit Rules, the Maricopa County Special Use Permit Stipulations, the Maricopa County Air Pollution Control Regulations, and the Maricopa County Zoning Ordinances and Regulations. Obtaining a permit or requesting the approval of certain operating plans, as well as strict compliance with such permits and plans, is mandatory. Failure to comply may result in the revocation of the permit or authorization, civil and criminal charges and fines, or potentially the closure of Solana.

In addition, in accordance with the National Environmental Policy Act (NEPA) designation of a Finding of No Significant Impact (FONSI) issued by the DOE, Solana must comply with certain water requirements due to the reduction in tail water runoff being contributed to a wash located near the site. In coordination with Arizona Game & Fish Department and the U.S. Fish and Wildlife Service, Solana must provide 447 acre-feet of water annually as a direct off-set to the reduction in tail water runoff from the site. This requirement is for the duration of Solana, and failure to comply would trigger an administrative procedure that could cause temporary closure of the plant until the non-compliance condition is cured.

Regulations Affecting Operating Generating Facilities in Arizona

Many of the permits obtained for Solana carry specific conditions that must be complied with during the operational phase of the facility and which are continuously monitored, measured, and documented by the Solana plant operators. The primary obligations that commenced during commissioning and/or commercial operation are those related to reliability, emergency response, potential hazards of waste disposal, and human health and safety. These requirements originate with federal laws, and in many cases are enforced via delegated authority from the appropriate federal agency to a state or county agency. These include:

- NERC Reliability Standards and Critical Infrastructure Plans, delegated to WECC as the regional authority;
- Emergency Planning and Community Right-to-Know Act, delegated to the Arizona Division of Emergency Management;
- Resource Conservation and Recovery Act, delegated to EPA Region 9 in San Francisco, California; and
- Occupational Safety and Health Administration federal requirements.

California

Regulation of Retail Electricity Service in California

The California Public Utilities Commission, or CPUC, governs, among other entities, California's three large investor-owned utilities, including Pacific Gas & Electric Company, or PG&E. PG&E is required to file an RPS procurement plan annually with the CPUC. Once the CPUC approves the plan, PG&E issues a request for offers, or RFO, for renewable energy. It then evaluates all of the bids using a "least-cost, best-fit" evaluation process approved by the CPUC and develops a short list of acceptable bids. In August 2008, Mojave was submitted as a renewable solar thermal project in response to PG&E's 2008 RFO solicitation and placed on their short list for additional negotiations. After two years of negotiations, PG&E and Mojave Solar executed a final PPA, for which PG&E filed with the CPUC an advice letter requesting approval of the PPA in July 2011. The CPUC reviewed the PPA and approved the contract by issuing a formal decision in November 2011. The terms of the PPA govern Mojave during its development, construction and operating period. The CPUC historically does not retroactively apply new regulations or rulings to previously approved PPAs that would result in any economic impact.

Performance and Operational Provisions of Mojave's PPA

The PPA executed between PG&E and Mojave's project company, Mojave Solar, contains provisions related to guarantees of performance (e.g., provision of minimum annual REC eligible energy quantities to PG&E). The provisions are largely intended to protect PG&E's ability to meet its mandatory requirements established by the CPUC, and to prevent PG&E from having to procure REC eligible power elsewhere at an unknown, and possibly higher, cost than the PPA price.

Siting and Construction of New Power Generation Facilities in California

The California Energy Commission, or CEC, is the lead agency for licensing thermal power plants 50 MW and larger under the California Environmental Quality Act and has a certified regulatory program under such Act. The CEC is comprised of five commissioners, two of whom oversee all hearings, workshops and related proceedings on a specific project. The CEC's siting process evaluates Applications for Certification, or AFCs, to ensure that only power plants that are actually needed will be built, provides review by independent staff with technical expertise in public health and safety, environmental sciences, engineering and reliability, ensures simultaneous review and full participation by all state and local agencies, as well as coordination with federal agencies, resulting in issuance of one regulatory permit within a specific time frame, with full opportunity for participation by public and interest groups.

On August 10, 2009, Mojave's AFC for its nominal 250 MW project was filed with the CEC. The CEC approved Mojave's AFC with the CEC decision issued on September 8, 2010. The CEC monitors the power plant's construction, operational phase and eventual decommissioning through a compliance proceeding.

Regulations Affecting Operating Generating Facilities in California

Mojave must maintain compliance with the CEC decision conditions of certification. These concern, among others, biological resources, health and safety, cultural resources, fire safety, and water. The conditions require Mojave to provide plans, notifications, and other reports on an ongoing basis. As noted above, such compliance is monitored by CEC staff. Per the CEC decision, "[f]ailure to comply with any of the Conditions of Certification or the compliance conditions may result in reopening of the case and revocation of Energy Commission certification; an administrative fine; or other action as appropriate." Additional regulations are administered by the California Independent System Operator and under the terms of the federally administered Large Generator Interconnection Agreement.

Regulation in Mexico

Overview

The following is a description of the regulation of the Mexican power industry applicable to the conventional or natural gas generation of electricity.

Pursuant to the Mexican Constitution, the electricity industry in Mexico was entirely controlled by the federal government, acting through the Federal Electricity Commission, or CFE, an entity wholly owned and controlled by the Mexican government, and legally independent from the Mexican Ministry of Energy, Secretaria de Energia. CFE was the only entity authorized to provide electricity directly to the public and to supply services to the Mexican wholesale market. CFE was also responsible for the construction and maintenance of infrastructure necessary for the delivery of electricity, such as the national electric grid, the Sistema Electrico Nacional, or SEN.

As a result of Mexico's energy reform bill enacted on December 21, 2013, articles 25, 27 and 28 of the Mexican Constitution were amended in order to end the long-standing state monopoly in the oil, petrochemical and power sectors, and allow private investment in these areas for their development in an open market. Hence, the power generation sector is now open to full private participation and investment, creating a competitive spot market in power generation, although electric transmission and distribution will remain public services to be provided exclusively by CFE. With the enactment of the secondary legislation, the generation, transmission, distribution and commercialization of power in Mexico is governed by a new legal framework which will likely improve the development of the sector.

Notwithstanding the legal changes, we do not expect any negative consequences for ACT Energy Mexico, or ACT, or for the power generated and delivered to Pemex Gas y Petroquimica Basica.

Until the recent energy reform, the whole set of activities regarding generation, transmission, distribution and commercialization of power for public use were considered areas of national strategic importance. As a result, such activities were carried out exclusively by CFE. The national electric grid was also controlled by CFE through the Centro Nacional de Control de Energia, or the CENACE, which operated the national electric grid and controlled delivery of all electricity generated by CFE and private generators connected to the grid. CFE is a vertically-integrated state monopoly that serves the whole country, and CENACE is a semi-independent agency that is part of CFE. As a result of the energy reform, CENACE became a decentralized public agency, which will continue to be responsible for the operation and control of the national electric grid with the aim of having an impartial third party (not CFE) operate the wholesale electricity market, guaranteeing open access to the national electric grid for both transmission and distribution of electricity. CENACE has emerged as an Independent System Operator, or ISO, which is a figure adopted worldwide in other mature energy markets.

The generation, transmission and distribution of electricity were regulated by the Ley del Servicio Publico de Energia Electrica, or Electricity Law; enacted in 1975 and amended in 1992. Since the implementation of the 1992 amendment to the Electricity Law, private entities have been allowed to participate in the following activities not considered public utility services, as defined by such law:

- *Cogeneration*. The electricity produced is used to supply power to the establishments associated with the cogeneration process and/or the shareholders of the cogeneration company;

- *Self-Supply Generation*. The electricity produced is used for the self-supply purposes of the holder of the relevant self-supply power generation permit and/or its shareholders;

- *Independent Power Production*. All the electricity produced is delivered to CFE;

- *Small-Scale Production*. The electricity produced does not exceed 30 MW and is used for export purposes or the supply of all power output is sold to CFE;

- *Exports*. The electricity produced is exported in its entirety; and

- *Imports for Independent Consumption*. The import of power is used for self-supply purposes.

The regulatory framework of the Mexican power industry is undergoing a transitory period, as the energy reform is still in the process of being fully implemented, given that the secondary legislation derived from such amendments to the Mexican Constitution was published in the Official Federal Gazette, or Diario Oficial de la Federacion, on August 11, 2014, and there are still several regulatory instruments pending issuance. See “Item 4.B—Business Overview—Regulation—Regulation in Mexico—Transitory Regime.”

The changes made by the energy reform are being implemented through a profound modification of the legal framework that had governed the development of the energy industry in the country, which has involved the entrance into force of new laws and the amendment of current laws.

The new laws enacted so far are listed below:

- Oil and Gas Law, or *Ley de Hidrocarburos*;

- Electric Industry Law, or *Ley de la Industria Electrica*;

- Geothermal Energy Law, or *Ley de Energia Geotermica*;

- Petroleos Mexicanos Law, or *Ley de Petroleos Mexicanos*;

- Federal Electricity Commission Law, or *Ley de la Comision Federal de Electricidad*;

- Energy Regulatory Bodies Law, or *Ley de los Organos Reguladores Coordinados en Materia Energetica*;

- National Industrial Safety and Environmental Protection Law of the Oil and Gas Sector, or *Ley de la Agencia Nacional de Seguridad Industrial y de Proteccion al Medio Ambiente del Sector Hidrocarburos*;

- Mexican Petroleum Fund for Stabilization and Development, or *Ley del Fondo Mexicano del Petroleo para la Estabilizacion y el Desarrollo*; and

- Oil and Gas Revenue Law, or *Ley de Ingresos sobre Hidrocarburos*.

Additionally, 12 laws were amended in order to unify their content with the new regulatory framework. The following are the amended laws:

- Foreign Investment Law, or *Ley de Inversion Extranjera*;

- Mining Law, or *Ley Minera*;

- Private Public Partnerships Law, or *Ley de Asociaciones Publico Privadas*;
- National Water Law, or *Ley de Aguas Nacionales*;
- Federal Law of Government-Owned Entities, or *Ley Federal de las Entidades Paraestatales*;
- Public Sector Acquisitions, Leases and Services Law, or *Ley de Adquisiciones, Arrendamientos y Servicios del Sector Publico*;
- Public Works and Related Services Law, or *Ley de Obras Publicas y Servicios Relacionados con las mismas*;
- Organizational Law of the Federal Government, or *Ley Organica de la Administracion Publica Federal*;
- Federal Fees Law, or *Ley Federal de Derechos*;
- Fiscal Coordination Law, or *Ley de Coordinacion Fiscal*;
- Federal Budget and Treasury Accountability Law, or *Ley Federal de Presupuesto y Responsabilidad Hacendaria*; and
- General Public Debt Law, or *Ley General de Deuda Publica*.

Furthermore, on October 31, 2014, the following regulations and regulatory instruments, which will contribute to the implementation of the aforementioned secondary legislation, were published in the Official Federal Gazette:

- Regulations of the Oil and Gas Law, or *Reglamento de la Ley de Hidrocarburos*;
- Regulations of the activities referred to in Chapter Three of the Oil and Gas Law, or *Reglamento de las actividades a que se refiere el Titulo Tercero de la Ley de Hidrocarburos*;
- Oil and Gas Revenue Law Regulations, or *Reglamento de la Ley de Ingresos sobre Hidrocarburos*;
- Electric Industry Law, or *Reglamento de la Ley de la Industria Electrica*;
- Geothermal Energy Law Regulations, or *Reglamento de la Ley de Energia Geotermica*;
- Regulations of Petroleos Mexicanos Law, or *Reglamento de la Ley de Petroleos Mexicanos*;
- Regulations of the Federal Commission of Electricity Law, or *Reglamento de la Ley de la Comision Federal de Electricidad*;
- Internal Regulations of the Mexican Ministry of Energy, or *Reglamento Interior de la Secretaria de Energia*; and
- Internal Regulations of the National Agency of Industrial Safety and Environmental Protection, or *Reglamento Interior de la Agencia Nacional de Seguridad Industrial y de Proteccion al Medio Ambiente del Sector Hidrocarburos*.

Additionally, the executive branch also published the following decrees, which amended the existing regulations of different laws and which are relevant for the development of the energy sector:

- Decree amending and supplementing various provisions of the Public Partnerships Law Regulation, or Decreto por el que reforman, adicionan y derogan diversas disposiciones del Reglamento de la Ley de Asociaciones Publico Privadas;
- Decree amending and supplementing various provisions of the Federal Budget and Treasury Accountability Law, or *Decreto por el que reforman, adicionan y derogan diversas disposiciones del Reglamento de la Ley Federal de Presupuesto y Responsabilidad Hacendaria*;
- Decree amending and supplementing various provisions of the Internal Regulation for the Ministry of Finance and Public Credit, or *Decreto por el que reforman, adicionan y derogan diversas disposiciones del Reglamento Interior de la Secretaria de Hacienda y Credito Publico*;
- Decree amending and supplementing various provisions of the Regulations of the Mining Law, or *Decreto por el que reforman, adicionan y derogan diversas disposiciones del Reglamento de la Ley Minera*;
- Decree amending and supplementing various provisions of the Regulations of the Foreign Investment Law and of the National Registry of Foreign Investment, or *Decreto por el que reforman, adicionan y derogan diversas disposiciones del Reglamento de la Ley de Inversion Extranjera y del Registro Nacional de Inversiones Extranjeras*;
- Decree amending and supplementing various provisions of the Internal Regulations of the Ministry of Economics, or *Decreto por el que reforman, adicionan y derogan diversas disposiciones del Reglamento Interior de la Secretaria de Economia*;
- Decree amending and supplementing various provisions of the Internal Regulations of the Ministry of Agrarian, Territory and Urban Development, or *Decreto por el que reforman, adicionan y derogan diversas disposiciones del Reglamento Interior de la Secretaria de Desarrollo Agrario, Territorial y Urbano*;
- Decree amending and supplementing various provisions of the Regulations of the General Law for Sustainable Forestry Development, or *Decreto por el que reforman, adicionan y derogan diversas disposiciones del Reglamento de la Ley General de Desarrollo Forestal Sustentable*;
- Decree amending and supplementing various provisions of the Regulations of the General Law of Ecological Balance and Environmental Protection on Environmental Impact Assessment, or *Decreto por el que reforman, adicionan y derogan diversas disposiciones del Reglamento de la Ley General del Equilibrio Ecologico y la Proteccion al Ambiente en Materia de Evaluacion del Impacto Ambiental*;
- Decree amending and supplementing various provisions of the Regulations of the General Law of Ecological Balance and Environmental Protection regarding prevention and Control of Air Pollution, or *Decreto por el que reforman, adicionan y derogan diversas disposiciones del Reglamento de la Ley General del Equilibrio Ecologico y la Proteccion al Ambiente en Materia de Prevencion y Control de la Contaminacion de la Atmosfera*;
- Decree amending and supplementing various provisions for the Regulations of the General Law for Prevention and Integral Waste Management, or *Decreto por el que reforman, adicionan y derogan diversas disposiciones del Reglamento de la Ley General para la Prevencion y Gestion Integral de Residuos*;
- Decree amending and supplementing various provisions of the Regulations of the General Law of Ecological Balance and Environmental Protection on Environmental Zoning, or *Decreto por el que reforman, adicionan y derogan diversas disposiciones del Reglamento de la Ley General del Equilibrio Ecologico y la Proteccion al Ambiente en Materia de Ordenamiento Ecologico*;

- Decree amending and supplementing various provisions of the Regulations of the General Law of Ecological Balance and Environmental Protection regarding Emissions to the Atmosphere and Transfer of Pollutants, or *Decreto por el que reforman, adicionan y derogan diversas disposiciones del Reglamento de la Ley General del Equilibrio Ecologico y la Proteccion al Ambiente en Materia de Registro de Emisiones y Transferencia de Contaminantes*;

- Decree amending and supplementing various provisions of the Internal Regulations of the Ministry of Environment and Natural Resources, or *Decreto por el que reforman, adicionan y derogan diversas disposiciones del Reglamento Interior de la Secretaria de Medio Ambiente y Recursos Naturales*; and

- Decree amending and supplementing various provisions of the Regulations of the General Law of Ecological Balance and Environmental Protection on Self-Regulation and Environmental Audits, or *Decreto por el que reforman, adicionan y derogan diversas disposiciones del Reglamento de la Ley General del Equilibrio Ecologico y la Proteccion al Ambiente en Materia de Autorregulacion y Auditorias Ambientales*.

Conventional Electricity Generation in Mexico

The former legal framework for conventional electricity generation in Mexico included the regulation of fossil fuels, such as carbon, diesel, fuel oil and natural gas, as well as nuclear fission regulation, which includes nuclear power plants and all related activities.

Accordingly, power generation under independent power production or self-supply schemes was not considered a public utility service and, therefore, could be performed by private companies and individuals pursuant to permits issued by the Energy Regulatory Commission, *Comision Reguladora de Energia*, or CRE. The CRE is a federal agency created in 1995 in order to enforce the laws and regulations relating to natural gas and electricity, and has the authority to issue permits, set tariffs, supervise, ensure adequate supply and, in the case of gas, promote competition.

As previously indicated, the Mexican federal government, acting through CFE, controlled the entire chain of activities related to electric power, including generation, sale, distribution and transmission. The energy reform allows the private sector to openly participate in two important parts of the production chain: the generation and the sale of electricity.

Pursuant to the reform, the private energy sector is now able to invest in electricity generation with the requisite permits. The sale of electricity by private parties has not yet begun (with the initiation of operations of Wholesale Electricity Market, *Mercado Electrico Mayorista*, or MEM) in Mexico under the new legal framework, privately sold electricity will be transmitted and distributed by CFE.

The reforms are expected to have positive effects on the electricity industry in Mexico, allowing the private sector to play an active role where a government monopoly once existed, generating greater investment and better technology.

As a result of the energy reform, the electricity sector will cease to be a chain of activities vertically integrated in a partially privatized sector, and become an area open to private investment in which, although CFE will maintain control, the possibility of private sector investment will be increased through a more flexible regulatory scheme that permits the execution of contracts to carry out various activities and the creation of new markets in the electricity sector. Among the most significant changes are the following:

- Participation open to the private sector in the generation of electricity through a permit granted by CRE. Private parties may also sell the energy generated and transmitted by CFE through commercial schemes.

- Participation of the private sector, together with CFE, in the activities of transmission and distribution through the execution of the corresponding contracts.

- Participation of the private sector in activities of financing, maintenance, management, operation and expansion of the power infrastructure through service contracts with CFE, with adequate compensation.

- Transformation of the CENACE into a decentralized public body responsible for the operational control of the national electric grid, so that it is an impartial third party (and not the CFE) that operates the wholesale electricity market, guaranteeing open access to the national electric grid, for both transmission and distribution of electric power.

- Creation of the MEM, operated by the CENACE, in which the participants carry out electric power purchase and sale transactions through contracts between the participants in the MEM. The CENACE is now responsible for managing the supply and demand of the MEM participants, carrying out transactions and generating prices continuously. The price that will be paid in the MEM transactions will be a competitive price, reflecting the costs of generation and other operating costs of electricity, as well as the volume of electric power demanded and supplied in the MEM.

- Creation of the trader, under the new Electric Industry Law, as the holder of a MEM participant agreement, which purpose is to carry out trading activities (execution of contracts for purchase and sale of electricity within the MEM, among others). The traders may sign contracts with qualified users (through the provider-trader) or execute such contracts with other traders (non-provider trader).

- The permits granted by the CRE under the currently repealed Electricity Law, will continue in force under its terms. The holders of those permits that choose to remain under the provisions of the Electricity Law may, at any time, transfer to the new rules.

- The Geothermal Energy Law, the purpose of which is to regulate the recognition, exploration and exploitation of geothermal resources for the use of underground thermal energy within the limits of Mexican territory, in order to generate electricity or use it otherwise.

- The activities regulated by the Geothermal Energy Law are considered to be in the public interest and their development will have preference over activities of other sectors when there is a conflict.

- The activities pursued under the Geothermal Energy Law will be carried out through different registries, permits, authorizations and concessions granted by the competent authorities applicable for each case. For exploration activities, a permit will be sufficient, while for exploitation activities, a concession will be required.

- Amendment of several articles of the National Water Law, for the purpose of (i) adapting certain definitions of that law to the new definitions introduced by the Geothermal Energy Law; (ii) including geothermal fields under regulated, prohibited or reserved zones; and (iii) establishing the obligation of requesting the relevant permits, authorizations and concessions from the National Water Commission in order to engage in the activities of geothermal fields exploration.

Electric Industry Law

The Electric Industry Law, as part of the package of secondary legislation that implements the constitutional energy reform, regulates planning activities, the control of the national electric grid, the public services of transmission and distribution of electricity, and all other activities related to the Mexican energy industry, in order to promote the sustainable development of the industry and to ensure its continuous, efficient, and secure operation for the benefit of all users, as well as the fulfillment of the obligations to provide a general and public service of electricity, to develop clean energies, and to reduce contaminating emissions.

Pursuant to the Electric Industry Law, the government holds the operational control of the national electric grid, through the CENACE, and CENACE, as an ISO, will indicate the elements for the national transmission grid and the related operations which may correspond to the wholesale market.

Regulations of the Electric Industry Law

The Regulations of the Electric Industry Law provide details for the application of the Electric Industry Law and complete the implementation of the restructured electric industry in Mexico.

These regulations expand on certain administrative procedures in the electric industry, such as the development of public bidding procedures by CFE, for private sector contracts for activities related to the national electric grid; the specific requirements for the application for power generation and power supply permits with CRE; the process for infrastructure contributions by the private sector to the State; and the registration of participants in the wholesale spot market with CENACE.

Permits and Authorizations

Pursuant to the Electric Industry Law, all power plants with a capacity greater than or equal to 0.5 MW and all power plants of all capacities represented by a generator (i.e., the holder of one or more generation permits or holder of a wholesale market participant agreement that represents the corresponding power plants in the wholesale market or, prior authorization granted by CRE, power plants located abroad) require a generation permit granted by CRE. Authorization granted by CRE is also required for the import of electricity from a power plant located abroad and interconnected exclusively to the national electric grid. Power plants of any capacity exclusively intended for personal use during emergencies or interruptions in electric supply will not require a permit.

The Electric Industry Law provides for several requirements which generators who represent power plants interconnected to the national electric grid have to comply with, including, among others, the execution of the corresponding interconnection agreements, issued by CRE. Regarding the production of their power plants, generators may carry out commercialization activities which include, among others, the following: (i) representing exempt generators (i.e., owner or holder of one or more power plants which do not require or have a generation permit) in the MEM; (ii) carrying out sale and purchase transactions of energy, related services included in the MEM, and power or other products which ensure enough resources to meet the electric demand, and all other products, duties or penalties required for the efficient operation of the national electric grid, among others; and (iii) executing, among others, the corresponding electric coverage agreements (i.e., agreement entered into by participants of the MEM which purpose is the sale and purchase of electric energy or related products) with other MEM participants, including other generators, traders (i.e., holder of a MEM participant agreement which purpose is to carry out commercialization activities), and qualified users (i.e., final user who is registered before CRE to acquire electricity supply as a MEM participant or through a qualified provider).

Pursuant to the former legal framework for the Mexican electric industry, permits for self-supply, cogeneration, independent production, small production, import, and export of electricity were granted by CRE for indefinite periods of time, except for independent power producer permits, which were granted for 30-year renewable terms. In addition to the legal and technical requirements established by law to obtain such permits, CFE's approval was required as part of CRE's permit approval process. Pursuant to the transitory regime, such permits will be in force for the duration of the corresponding interconnection agreements executed under their scope.

CRE may also issue a supply permit for private parties, which will allow companies to participate in the MEM by carrying out transactions with final users, which are called “qualified users.” In this sense, private parties may supply power directly to consumers through bilateral long-term agreements, which will be partially regulated by the CRE.

Consequently, the Mexican power industry had been divided into two main areas: (i) the public service of electricity under CFE’s control, and (ii) the activities where private parties may be involved (such as where CFE actively promoted private investment in the construction and operation of power plants for supplying CFE and private parties under self-supply and cogeneration schemes).

While power generated in Mexico is still predominantly generated by CFE, there is a large amount of electricity generated by private energy producers, which generally fall under the categories of independent power production and self-supply generation, although cogeneration has come to be a relevant source of power as a result of certain amendments enacted in 2006 which allowed Pemex to develop new cogeneration projects independently and in collaboration with CFE. These amendments allowed Pemex to enter into the Pemex conversion services agreement and to receive the power generated by ACT.

As a consequence of the corresponding reforms the issuance of a new class of permit available to those interested in generating electricity is provided for pursuant to the Electric Industry Law. This permit will expand the ways in which entities are allowed to participate as energy producers under the Electric Industry Law and is within the scope of the CRE’s regulatory control.

The permits provided for in the Electric Industry Law are, as aforementioned, granted and issued by CRE, upon prior submission of the corresponding application, payment of the corresponding duties, all relevant legal and technical information, and project description. Such permits will be terminated or revoked pursuant to the different scenarios indicated in the Electric Industry Law and its regulations, and as determined by CRE.

The regulations list the documentation to be submitted to apply for a permit with CRE, as well as the corresponding timeline for the application procedure and the essential elements that CRE must include in the permit title.

Transmission and Distribution of Electricity in Mexico

Pursuant to the Electric Industry Law, regarding conventional energy generation, dispatchers and distributors are responsible for the national transmission grid and the general distribution grids and will operate their grids pursuant to the instruction provided by CENACE. Whereas in the past there were no regulatory limitations that would interfere with a private generator engaging in transmission activities, and, regarding distribution activities, these could only be performed by CFE, with the new regulatory framework derived from the constitutional reform and the legal provisions therein, the public service of electricity and its transmission are considered as strategic areas and will continue to be government-controlled, notwithstanding the possibility of the Mexican government, acting through CFE, to be able to enter into agreements with the private sector, or, acting through the Mexican Ministry of Energy, to form partnerships or enter into agreements with the private sector to carry out the financing, installation, maintenance, administration, operation or expansion of the infrastructure required to provide electricity transmission and distribution services, in terms of the provisions of the Electric Industry Law.

Such agreements will be awarded to private companies through bidding rounds, conducted by CENACE, which will determine the needs of the national electric grid, and carry out the corresponding tender processes. In addition, all dispatchers and distributors will have the obligation to execute the corresponding connection and interconnection agreements, based on the model contracts issued by CRE, regarding the interconnection of power plants or the connection of load centers, and the MEM regulations will indicate the criteria for CENACE to define the specifications for the required infrastructure necessary for the interconnection of power plants and the connection of load centers, as well as the mechanisms to determine preference matters for applications or requests and the procedure for their evaluation.

CFE is required by law to provide its wheeling (the transfer of electrical power through transmission and distribution lines to another utility), dispatch and backup services to all permit holders whenever the requested service is technically feasible on a first-come, first-served basis. CFE's wheeling services are provided pursuant to an interconnection agreement and a transmission services agreement entered into between CFE and the relevant permit holder (in ACT's case, these were executed by Pemex). Those agreements follow model contracts approved by the CRE, which also approves the methodology used to calculate the applicable tariffs. The permit holders must build their own transmission lines for self-use in order to connect to the power grid. In addition, permit holders are required to enter into a back-up services agreement with CFE, which also follow a model agreement approved by the CRE.

The Electric Industry Law incorporates new requirements to carry out the sale and purchase of electricity. Aside from being classified as a generator or qualified user, along with the need to comply with the rules issued by CRE for the execution of the corresponding agreements, there are new requirements for the interconnection to the transmission grid owned by CFE. The Electric Industry Law introduces and provides for the concepts of connection and interconnection, the first referring to the load points of users and the latter referring to generators' power plants. Regarding interconnection, the most significant change is the need to execute new model agreements in order to adapt them to the new modalities and activities under the scope of regulation of the Electric Industry Law.

Furthermore, the transitory provisions contained in the Electric Industry Law provide that those interconnection agreements which were executed under the scope of regulation of the Electricity Law will remain in force, notwithstanding the possibility that executing the new contract models that will be issued by CRE may prove beneficial in order to adapt to the new changing aspects of the industry; as with previous agreements, companies will only be limited to the authorized activities under such contracts (e.g. wheeling will only be available for the amount of energy and for the specific purpose established therein). This suggests that new models of interconnection agreements may be more flexible to cover the implementation of the various activities allowed.

The regulations provide that CRE must implement a regulatory regime providing for the conditions for the procurement of the public services of transmission and distribution of electric power based on the principles of proportionality and equality, aiming to prevent transporters, distributors and suppliers from exercising excessive market power that could negatively affect final users. Such regulatory regime will consider the degree of openness in the market, the concentration of participants and any other condition of the competition in every division of the industry. The regulations also anticipate the possible cases of curtailment of the services of transmission and distribution of electric power and provide for standard procedures in different situations.

Commercialization of Electricity

Under the Electric Industry Law, the trader will be the holder of a MEM participant agreement, and will carry out commercial activities, among which are executing electric coverage agreements for the sale and purchase of electricity within the MEM. Under the Electric Industry Law, electric coverage agreements are those agreements executed between MEM participants through which those participants engage in the sale of electric energy or related products. Traders may enter into such agreements with qualified users (through the figure of the provider-trader) or with other traders (who are not providers).

Excluding qualified users, basic providers will provide the basic supply to all people who so request it and whose load centers are located in their operation areas. Qualified providers will provide the qualified supply to qualified users in terms of free competition. Prior commencement of the qualified or basic supply services, the final user must execute a supply agreement with the appropriate provider, and such agreements will require registration before the Federal Attorney's Office of Consumer, or *Procuraduria Federal del Consumidor*, or PROFECO, CRE will issue the general terms and conditions for the electrical supply services, which will determine the rights and obligations of the service provider and the final user, correspondingly.

Qualified users are those final users who are duly registered as such before CRE in order to acquire power as MEM participants or by a qualified provider. In terms of the Electric Industry Law, users holding load points with a demand greater than or equal to 3 MW may be included in the qualified users registry (but such amount will decrease in one MW per year following the first year until reaching 1 MW). In this case, having the property in which the electric power is intended to be supplied registered as qualified under the corresponding rules to be issued will suffice. Within the MEM, qualified users may purchase energy through electric coverage agreements executed with CENACE or directly with traders.

Supply

Supply activities carried out in the new electric industry may be either in the basic or qualified modalities. Power supply agreements will be executed by and between providers and final users, under the corresponding supply permits issued by CRE. Basic supply refers to that which is provided by a provider under a regulated tariff to any applicant who is not a qualified user. Qualified Supply refers to that which is provided in terms of free competition to qualified users.

For basic supply, private generators may participate in the auctions conducted by CENACE, in order for CFE to acquire the energy in the most convenient economic terms and conditions, and thus CFE will be able to supply power to users who so request it before CENACE, who will carry out the referred auction and determine whom the electricity will be purchased from. CRE will also determine the requirements that providers must comply with in order to acquire energy and execute contracts for electric coverage with users.

As for qualified supply, qualified providers will carry out transactions directly through long-term supply agreements with qualified users. Under these agreements, the parties will be free to agree upon the terms and conditions (including economic conditions) thereof, abiding by certain general guidelines that will be issued by CRE.

Open Access

Both the Electric Industry Law and in the regulations thereunder establish that CFE will be obligated to grant non-discriminatory open access to all users of the national electric grid. This will enhance the existence of an open electricity market, where various competitors in almost all segments of the supply chain requiring the use of the national electric grid will coexist and develop their activities. Open access is a crucial component of the electric industry since CFE, as owner of the grid, will compete directly with other private sector participants in several activities of the industry, which could lead to a monopoly by CFE. In order to avoid such situation, the CENACE, as an independent system operator, will ensure competitive conditions for all users who want to use CFE's infrastructure.

Pursuant to the regulations, CRE issued the general guidelines regarding open access conditions, the procedure for users to request such open access and the procedure to which the CENACE will be subject to grant this open access, among others.

Tariffs

Transmission, distribution, basic supply and last resort supply, as well as the operation of CENACE, will be subject to regulatory accounting guidelines established by CRE. CRE is currently issuing general administrative provisions regarding the methodology to determine the calculation and adjustment of the regulated tariffs for transmission, distribution, basic provider operation and CENACE operation services, as well as all related services which are not included in the MEM.

Dispatchers, distributors, basic providers and the CENACE will be required to publish their tariffs, as indicated by CRE, through general administrative provisions.

Wholesale Spot Market, Mercado Electrico Mayorista

The Electric Industry Law provides for the creation of a MEM, operated by CENACE, in which Participants can carry out a number of different transactions provided for in said law, among which are the sale of electricity and related products.

MEM participants can be (i) generators, (ii) provider-traders, (iii) non-provider traders, or (iv) qualified users, prior to execution of the corresponding agreement with CENACE. Transactions carried out within the MEM must be formalized through “electric coverage agreements” executed by and between such MEM participants. Generators, as MEM participants may, sell their generated energy and both traders and qualified users may purchase such energy through CENACE, which is the independent operator of the electric system.

CENACE is responsible for managing the supply and demand of MEM participants, conducting transactions and continuously generating prices. The price to be paid in MEM transactions has to be a “competition price” in terms of the Electric Industry Law and has to reflect elements such as electricity generation costs and other operating costs, as well as the amount of electricity demanded by and supplied within the MEM. Such competition price will serve as a reference for long-term supply agreements between providers and qualified users, partially replacing the current CFE-published tariffs.

Even though the Electric Industry Law provides the general guidelines to which the operation of the MEM is subject, on September 8, 2015, the Mexican Ministry of Energy published the Guidelines of the Market (*Bases del Mercado Electrico*), as the general administrative provisions which establish the principles for the design and operation of the MEM. The regulations list certain topics which will be described in depth in the Rules of the Market (*Reglas del Mercado)*, such as the methodology that will be used to forecast the level of demand in the spot market, information on market participants, and the methodology to determine the price of the electricity that will be sold and purchased within the spot market.

The Guidelines are part of the Rules of the Market, (which are administrative provisions of general application that will specifically detail different aspects of the operation of the MEM, and determine the rules that all market participants as generators, traders, suppliers, non-supplier traders or qualified users, as well as the competent authorities must comply with, and the procedures they must follow in order to maintain the proper management, operation and planning of the MEM. Pursuant to the Guidelines, which will subsequently be supplemented by guidelines for market practices, operational guidelines and criteria and operating procedures (some of which have already been issued), the different participants of the electricity industry will be able to carry out activities which are now open to private participation, due to the so-called Energy Reform that took place in late 2013, and which were regulated through the Electric Industry Law and its Regulations (such activities include, among others, transactions of sale of electricity and related services, power, financial transmission rights and clean energy certificates.

Public Consultation

The Electric Industry Law and the regulations thereunder set out the obligation to carry out a prior consultation process in the event a project is to be developed in certain lands where communities or indigenous people are found. This obligation, which is established in international treaties, as well as in Article 2 of the Political Constitution of the United Mexican States, is now established in the new legal framework to provide certainty regarding community and social issues in all projects within the electric industry.

The aforementioned general obligation is provided for in the Electric Industry Law and the regulations thereunder detail the specific procedure to be followed, including the filing of a social and cultural impact assessment before the Mexican Ministry of Energy and the different stages that the prior consultation entail, among others.

Transitory Regime

Given that the Electric Industry Law sets various deadlines for the full implementation of its provisions (such as the issuance of the Market Rules pending to be determined, the full entry into operation of the MEM or the Terms and Conditions for the Supply of Electricity), a transitory regime has been established, intending to provide clarity and certainty to all participants of the industry who either have ongoing projects or plan to start projects in the near future.

Permits

Permits granted by CRE, in accordance with the Electricity Law, will continue to be governed under the terms set out therein and other applicable provisions. Holders of such permits who decide to remain under the regulation of Electricity Law may, at any time, migrate to the new regime if it suits their interests.

Interconnection agreements

In order to be able to execute an interconnection agreement in terms of the Electricity Law (in the event not previously executed), those interested in doing so must comply with the following conditions: (i) having obtained or having applied for a permit in any of the modalities provided by the Electricity Law, prior to the entry into force of the Electric Industry Law (August 11, 2014); (ii) having notified CRE about its intention to continue with the development of the relevant project; and (iii) having provided proof evidencing that the appropriate financing for the project has already been obtained, that they have already contracted the supply of the main equipment required for the project, and that at least 30% of the total investment for the project has been paid before December 31, 2016. Additionally, it is possible to execute an interconnection agreement in terms of the Electricity Law if a company participated in an open season process, through which CRE granted transmission capacity to several participating companies.

The Electric Industry Law also provides certainty regarding interconnection agreements which have been executed with CFE prior to the enactment of the Electric Industry Law, as those agreements which were executed under the scope of regulation of the Electricity Law will remain in force for their entire duration (although they will not be subject to renewal or extension upon their termination). With the enactment of the Electric Industry Law, it is now possible to modify executed interconnection agreements in relation to the load points, surplus sales, support services, cost of stamp wheeling and other conditions contained therein which may apply.

Permit holders who choose to remain under the scope of regulation of the Electricity Law and decide to keep their interconnection agreements will be governed by the terms and conditions set forth therein and, consequently, will not be subject to the rules of the MEM.

Former Regulatory Framework

The following laws and regulations include constitutional, legal and administrative provisions applying to the development of cogeneration projects in Mexico, according to the former regulatory framework:

- **The Mexican Constitution**. Pursuant to articles 25, 27 and 28 of the Mexican Constitution, the supply of electricity, a public service in Mexico, including its generation, transmission, transformation, distribution and sale are activities expressly reserved to the Mexican federal government.

- **Electricity Law**. Along with its regulations, this law provides the main legal framework through which the Mexican federal government, acting through CFE, provides the public its electricity supply, as well as the regulations applicable to power generation, sale and purchase for the private sector.

- **Law of the Energy Regulatory Commission**, *Ley de la Comision Reguladora de Energia*. This regulates the manner in which the CRE operates.

- **Resolution number RES/146/2001, issued by the CRE: Fee Calculation Methodology for Electricity Transmission Services**, *Metodologia para la determinacion de los cargos por servicios de transmisionn de energia electrica*. This regulation provides the mechanism pursuant to which CFE will calculate the appropriate charges for the requests of transmission services.

- **Interconnection Agreement**, *Contrato de Interconexion*, issued by the CRE.

- **Transmission Agreement**, *Convenio de Transmision*, issued by the CRE.

- **Methodology and criteria for high-efficiency cogeneration**, *Metodologia y criterios de cogeneracion eficiente*.

- **Guidelines for the validation as high-efficiency cogeneration systems** (*Disposiciones para acreditar sistemas de cogeneracion eficiente*).

Current Regulatory Framework

The following laws and regulations include constitutional, legal and regulatory provisions applying to the development of cogeneration projects in Mexico, according to the recently enacted regulatory framework:

- Political Constitution of the Mexican United States

- Electric Industry Law

- Regulation of the Electric Industry Law

- Law of the Federal Commission of Energy

- Law of the Coordinated Regulatory Agencies in Energy Matters

- Energy Transmission Law, or *Ley de Transicion Energetica*

- Guidelines of the Market

Notwithstanding the above-listed regulatory framework, it is noteworthy that this list remains subject to modifications, as the pending regulatory instruments are to be issued in coming months, and, pursuant to the transitory regime provided for in the new framework, certain former legal provisions will continue to be in force, as applicable, for specific projects which were started before the enactment and implementation of the new legal framework.

Regulation in Peru

Below is a general overview of certain Peruvian electricity sector regulations. This overview should not be considered a full description of all regulations.

The Electric Transmission Sector

The Peruvian electric system serves energy to a large area of the country through the SEIN that has transmission lines and substations operating at 500, 220, 138, 69 and 33-kV levels.

Pursuant to Law 28832, which is applicable to any transmission project commissioned after July 2006, the transmission facilities integrating the transmission grid are classified as those belonging to: either (i) the SGT for transmission facilities that are included in the transmission plan and developed pursuant to a concession agreement granted by the Peruvian government to the winner of a public tender, or (ii) the Complementary Transmission System, or *Sistema Complementario de Transmision*, or SCT, for transmission facilities that are either (a) included in the transmission plan and developed by the private entity that was awarded a concession as a result of the successful review of a private initiative proposal, or (b) not included in the transmission plan.

Under Law 28832, the projected expansions of the transmission system identified in the Peruvian transmission plan are part of the SGT. The government organizes tender procedures to call private investors interested in building the projected lines of the SGT. Under SGT concession agreements, the concessionaire shall build the lines and be responsible for their operation and maintenance. Recovery of the investment during the term of the contract (up to 30 years) is guaranteed thereunder. The concessionaire owns the transmission assets during the term of the contract. Upon expiry of the contract the assets return to the State which shall call a new tender if the lines are required at such time for the operation of the system.

Transmission lines of interest to generation plants, distribution networks or large consumers are part of the SCT. The lines of the SCT included in the Peruvian transmission plan and certain projects that exclusively serve the demand, as defined by the government, may be subject to tenders for the granting of SCT concession agreements up to 30 years. The rest of the SCT projects are subject to the general regime in which the owners of the SCT lines (for example, the generation companies building them to connect their plants to the system) are the holders of the respective Definitive Transmission Concession and own the transmission assets through the term of the concession.

Open Access Regime

The activity of electricity transmission is a public service according to Peruvian law; such service is subject to open access regulations, which imply that the owner of a transmission infrastructure is obliged to allow third parties to connect to the SEIN through its transmission facilities. However, third parties requesting access to a transmission system have the obligation to assume the costs of any additional investment required to increase the connection capacity, if required to make the interconnection feasible. The terms and conditions of the required new investments shall be negotiated in an interconnection agreement.

Access of third parties to the SGT with facilities that are not included in the Peruvian transmission plan requires a previous verification by the Comite de Operacion Economica del Sistema Interconectado Nacional, or COES, of the technical conformity of such connection facilities. For those facilities needed for the electrical continuity of the SGT, the third party seeking access assumes the costs of expansion and compensation for their use, and the corresponding SGT concessionaire is responsible for the implementation, operation and maintenance of these facilities. The operation and maintenance costs of these facilities are those arising from the agreement between the SGT concessionaire and the third party seeking access.

Pursuant Peruvian Law, the concessionaire owns the transmission infrastructure needed for the electrical continuity of the SGT. These infrastructures will be concession assets under the contract. Upon expiry of the contract the assets return to the State.

If a private interconnection agreement is not reached through private negotiation, a request for an interconnection mandate can be filed before the *Organismo Supervisor de la Inversion en Energia y Mineria*, or OSINERGMIN, who will determine the conditions applicable to the connection, if it is technically feasible. To that end an assessment of the different connection possibilities shall be submitted to OSINERGMIN by the applicant to determine the most efficient technical solution.

The participation of OSINERGMIN shall guarantee and enforce compliance with the legal principle of open access to transmission and distribution networks. An interconnection mandate establishes the conditions under which the interconnection shall take place. The parties usually prefer to reach an agreement establishing those conditions. However, in cases where an agreement is not feasible due to the pre-existence of previous interconnection commitments with other companies, OSINERGMIN has been willing to grant new interconnection mandates as long as there is available capacity.

Tariff Regime

The SGT is compensated through the tariff base, which is the authorized annual remuneration for facilities belonging to the SGT. The tariff base is established in annual amounts and includes the following: (i) remuneration of investments (including adjustments), which is calculated based on a 30-year recovery period applying a 12% rate of return, (ii) efficient operating and maintenance costs, and (iii) the liquidation of imbalances between the authorized tariff base for the previous year and the proceeds obtained during that year.

The tariff base will be paid through the (i) tariff income and (ii) the transmission toll. The tariff income is paid monthly by the electricity generation companies in proportion to their respective capacity income. The transmission toll is paid by the electricity generation companies based on their collection of the transmission toll paid by their respective customers pursuant to Article 26 of Law 28832 and Article 27 of the Transmission Rules, or Reglamento de Transmision, approved by the Supreme Decree No. 027-2007-EM.

The electricity generation companies are paid by customers via capacity charges and energy charges established in their respective supply contracts. These capacity charges include a transmission toll per unit of peak demand (5% per kW-month) needed to cover the costs to be paid for the SGT.

The monthly payments to be made by electricity generation companies to the transmission companies are liquidated by the COES, in application of the tariffs determined by OSINERGMIN. A portion of the amount collected by the electricity generation companies from customers is allocated to the transmission companies that own facilities in the SGT. As such, electricity generation companies collect the money required to pay the SGT facilities from customers.

Non-regulated customers include large electricity consumers with a maximum annual power demand over 2,500 kW and customers with maximum annual power demands between 200 kW and 2500 kW that may choose to be regulated customers or not. Non-regulated customers may freely negotiate their energy prices with suppliers.

The SCT is remunerated on the basis of the annual average cost of the corresponding facilities approved by OSINERGMIN. The applicable tariffs and their respective actualization formulas are approved by OSINERGMIN every four years.

Penalties

The concessionaires must maintain certain quality, safety and maintenance standards of the facilities. The failure to meet the quality standards established by applicable industry regulations, such as the Technical rules of quality for power services, approved by Supreme Decree No. 020-97-EM, and the National Power Code, may result in the imposition of penalties, fines and restrictions. In addition to these penalties, fines and restrictions, if our concession is terminated due to the breach of obligations under the Concession Agreements, the Peruvian Ministry of Energy may appoint an intervenor to supervise the operations related to the concession to ensure the continuity in the provision of the service, and the compliance with applicable laws and regulations.

If a concessionaire suspends or interrupts the service for reasons other than regular maintenance and repairs, force majeure events, or failures caused by third parties, such concessionaire may be required to indemnify those who were affected for the damages caused by any such service interruption, in accordance with applicable regulations. In addition, the OSINERGMIN could impose penalties, including, among others, (a) admonishment, (b) successive fines, depending on the nature and effect of the interruption and its frequency, (c) temporary suspension of activities, and (d) definitive suspension of activities and the provisional administration of operations by an intervenor, if a termination event occurs and the Peruvian Ministry of Energy notifies of its desire to terminate the SGT concession agreement.

Also, OEFA (Agency of Environmental Evaluation and Control), the entity in charge of the supervision, inspection and sanction concerning environmental matters, may impose fines and corrective measures to the companies in case of violation of the environmental rules and regulations.

Electricity Legal Framework

The principal laws and regulations governing the Peruvian power sector, or the Power Legal Framework, are: (i) the Power Concessions Law (or *Ley de Concesiones Electricas*, PCL), approved by Law No. 25844, and its implementing rules (Supreme Decree No. 09-93-EM); (ii) the Law to Ensure the Efficient Development of Electricity Generation (or *Ley para Asegurar el Desarrollo Eficiente de la Generacion Electrica*), approved by Law No. 28832, or Law No. 28832; (iii) the Transmission Rules (or *Reglamento de Transmision*), approved by the Supreme Decree No. 027-2007-EM, or the Transmission Rules; (iv) the General Environmental Law (Law No. 28611); (v) the Rules for the Environmental Protection in Power Activities (Supreme Decree No. 029-94-EM); (vi) the Power Sector Antitrust Law (Law No. 26876) and its regulations (Supreme Decree No. 017-98-ITINCI); (vii) the Laws creating OSINERGMIN (Law No. 26734 and Law No. 28964); (viii) the OSINERGMIN Rules (Supreme Decree No. 054-2001-PCM); (ix) the Regulatory Agencies of Private Investment in Public Services Framework Law (Law No. 27332); and (x) the Legislative Decree that promotes investment in the generation of power through renewable resources (Legislative Decree No. 1002) and its regulations (Supreme Decree No. 012-2011-EM).

These laws regulate how to enter the electricity sector (applicable permits and licenses); the main obligations of the different participants of the electricity market (generators, transmission companies and distribution companies); remuneration systems for the different market participants; rights of electricity consumers and the attributions of the competent authorities.

Other relevant laws are: (i) the Public Consultation Law and its regulations (Law No. 29758 and Supreme Decree No. 001-2012-MC) for projects that may affect rights of indigenous and native communities and (ii) Law of National Heritage (Law 28296) and relevant regulations (Supreme Resolution No. 004-2000-ED) for obtaining the CIRA which is issued by the Ministry of Culture, certifying there are no archaeological remains in an area. Prior to performance of any activity or construction works, titleholders shall obtain the corresponding CIRA.

Some of the main aspects of Peru's regulatory framework concerning its power sector are: (i) the separation between the power generation, transmission and distribution activities; (ii) unregulated prices for the generation of power supplied to unregulated customers; (iii) regulated prices for the generation of power supplied to regulated customers; (iv) regulated prices applicable to transmission and distribution of power for both regulated and unregulated customers; and (v) the private administration of the SEIN, according to the principles of efficiency, cost reduction, guaranty of quality and reliability in the provision of services.

All entities that generate, transmit or distribute power to third parties in Peru, including self-generators and co-generators that sell their excess capacity and energy in the SEIN, are regulated by the Power Legal Framework.

Although significant private investments have been made in the Peruvian power sector and independent entities have been created to regulate and coordinate its oversight, the Peruvian government still retains ultimate oversight and regulatory control. In addition, the Peruvian government owns and controls various generation and distribution companies in Peru.

The Guaranteed Transmission System—SGT Concession Agreement

ATN and ATS (now, ABY Transmision Sur S.A.), as concessionaires, have SGT concession agreements granted by the Peruvian government as a result of a public tender.

Under the SGT concession agreement, the Peruvian Ministry of Energy grants the concession necessary to construct, develop, own, operate, and maintain the transmission lines and substations comprising a project to provide electricity transmission services that has been included in the Peruvian transmission plan.

The SGT concession agreement must specify the works schedule of the project and the corresponding guaranties of compliance. It also specifies the causes of termination of the agreement. The SGT concessionaires are not obliged to pay the grantor any consideration for the SGT concession agreement.

Under the SGT concession agreement, the concessionaire shall build the lines and be responsible for their operation and maintenance. The recovery of the investment during the term of the contract (30 years) is guaranteed thereunder. The concessionaire owns the transmission assets during the term of the contract. Upon expiry of the contract the assets return to the state, which shall call a new tender if the lines are required at such time for the operation of the system.

In addition to the SGT Concession Agreement, the SGT concessionaire should obtain from the Peruvian Ministry of Energy a Definitive Concession, or the Definitive Concession, which entitles such concessionaire to develop the activity of electricity transmission. The Definitive Concession will be granted for the term of the SGT concession agreement, and under the terms and conditions of the latter (among others, the works schedule of the project).

Under the Definitive Concession, if the concessionaire requests it, the grantor shall impose easements on the lands required for the execution of the project in accordance with applicable laws, but the grantor does not assume the costs associated with such easements.

Under the SGT concession agreement upon request, the grantor is also required to use its best efforts to assist in obtaining licenses, permits, authorizations, concessions and other rights when the owner of the project complies with the legal requirements to obtain them and they are not granted on a timely basis by the competent authorities.

Revenues

The revenues of the project are established under the terms of the SGT concession agreement. In addition, the revenues of the project are funded by the users of electricity system.

In effect, the compensation for facilities that are part of the SGT is allocated to customers by OSINERGMIN according to the amounts of investment, operational and maintenance costs set forth in the SGT concession agreement. The SGT will receive monthly compensation from the generation companies that collect the tariff base from their customers. Their compensation will be paid on a monthly basis and these monthly payments are liquidated by the COES, following the tariffs established annually by OSINERGMIN.

As of the commercial operation date, the owner of a project receives the revenue from payments of the tariff base pursuant to the SGT concession agreement. The calculation of the tariff base is based on: (i) an amount which represents a return on investment, including operation and maintenance costs and (ii) the amount determined on May 1 of each year by OSINERGMIN, in order to compensate for any intra-year difference between the compensation we should have received in the immediately preceding tariff year in U.S. dollars and the amount actually paid in Peruvian soles, determined at the exchange rate published in the Official Gazette "El Peruano" on the last working day prior to the fifteenth day of the month following the relevant month for which the services were charged to the electricity generation companies.

Every year, before the beginning of the new tariff period, OSINERGMIN will recalculate and determine the tariff base in U.S. dollars for the period which starts from May 1 of such year to April 30 of the following year. This determination is approved in April of each year through a resolution published in the Official Gazette, "El Peruano."

Regulation in Spain

On November 26, 1997, the European Union published a report, or White Paper, which outlined a strategy and a community-wide action plan aimed at doubling energy production from renewable energy sources in the European Union from 6% in 1996 to 12% by 2010. The White Paper proposed a number of measures to promote the use of renewable energy sources, including measures designed to provide renewable energy sources better access to the electricity market. The Kyoto Protocol, ratified by the EU and its Member States on May 31, 2002, imposed a target of reducing EU emissions of greenhouse gases by 8%

Directive 2009/28/EC on the Promotion of the Use of Energy from Renewable Sources of the European Parliament and of the Council of the European Union, or the 2009 Renewable Energy Directive, set mandatory national overall targets for each Member State consistent with at least 20% of EU total energy consumption coming from renewable energy sources by 2020. In order to comply with these mandatory renewable energy targets, all EU Member States, including Spain, were required to develop a national action plan, called a National Renewable Energy Action Plan, or NREAP. Spain's NREAP was issued on June 30, 2010 and sent to the European Commission.

In its NREAP, Spain set a target of 22.7% for primary energy consumption to be supplied by renewable energy sources and a target of 42.3% of total electricity consumption to be supplied by renewable energy sources by 2020.

In 2011, a new Renewable Energies Plan, referred to as REP 2011-2020, was developed by the European Parliament and the Council of the European Union under the 2009 Renewable Energy Directive that added a new target to the 2009 Renewable Energy Directive, a minimum of 10% of transportation energy consumption to be supplied from renewable energy sources in each Member State by 2020.

In Spain, these targets mean that energy from renewable sources should represent at least 20% of total energy consumption by 2020, consistent with the EU target, with a minimum of 10% of transportation consumption to be derived from renewable sources by that same year.

Article 3.3(a) of the 2009 Renewable Energy Directive states that in order to reach the targets set for 2020, Member States may apply support schemes and incentives for renewable energy. These support systems or incentives are different in each country, but the most common are:

- *Green certificates*. Producers of renewable energy receive a “green certificate” for each MWh they generate, and suppliers of energy have an obligation to purchase part of the energy that they supply from renewable sources.

- *Investment grants and direct subsidies*. These help defray the costs of installing renewable energy generation plants.

- *Tax exemptions or relief*. These include ITCs, cash grants in lieu of tax credits and accelerated depreciation, among others.

- *System of direct support of prices*. These include regulated tariffs and premiums and involve a regulatory guarantee to purchase energy generated by a renewable energy plant for an allotted period of time at a fixed tariff per kWh, for a maximum annual number of hours, so that the producer is ensured of a reasonable return on its investment.

Regulatory Framework Applicable to Solar Power Plants Currently in Operation

The applicable legal framework for solar power plants already in operation is set out in the following legal instruments:

- Royal Decree-law 9/2013, of July 12, containing emergency measures to guarantee the financial stability of the electricity system, referred to as Royal Decree-law 9/2013;

- Law 24/2013, of December 26, the Electricity Sector Act, referred to as the Electricity Act;

- Royal Decree 413/2014, of June 6, regulating electricity production from renewable energy sources, combined heat and power and waste, referred to as Royal Decree 413/2014;

- Ministerial Order IET/1045/2014 of June 16, published on June 20, 2014, approving the remuneration parameters for standard facilities, applicable to certain electricity production facilities based on renewable energy, cogeneration and waste, referred to as Revenue Order;

- Ministerial Order IET/1882/2014 of October 14, published on October 16, 2014, establishing the methodology for the calculation of the electricity associated to the gas consumption in CSP plants; and

- Ministerial Order ETU/130/2017 of February 17, published on February 22, 2017, updating the remuneration parameters for the existing standard renewable energy installations applicable from 1 January 2017, referred to as Updated Parameters Order.

Primary Rights and Obligations under the Electricity Act

The Electricity Act eliminates a previously existing distinction between ordinary electricity producers and those using renewable energy sources in their production of electricity, though it continues to recognize the following rights for producers with facilities that use renewable energy sources:

- *Priority off-take*. Producers of electricity from renewable sources will have priority over conventional generators in transmitting to offtakers the energy they produce over conventional generators under equal market conditions, subject to the secure operation of the national electricity system and based on transparent and non-discriminatory criteria.

- *Priority of access and connection to transmission and distribution networks*. Producers of electricity from renewable energy sources will have priority in obtaining access and connecting to the grid, subject to the terms set forth in the regulations, on the basis of objective, transparent and non-discriminatory criteria.

- *Entitlement to a specific payment scheme*. Producers of electricity from renewable sources will receive specific reimbursement that shall not exceed the minimum amount necessary to cover their costs. This enables them to compete on a level playing field with the other, non-renewable technologies on the market while achieving a reasonable return on investment.

The significant obligations of the renewable energy electricity producers under the Electricity Act include a requirement to:

- Offer to sell the energy they produce through the market operator even when they have not entered into a contract and so are excluded from the bidding system managed by the market operator.

- Maintain the plant's planned production capacity. Power lines, which include connections with the transmission or distribution network and transformers, are considered part of the production facility.

- Contract and pay the corresponding fees, whether directly or through their representatives, to the transmission or distribution companies to which the renewable energy facilities are connected in order for their power to be fed into the grid.

Registration on Public Registers

The Electricity Act and Royal Decree 413/2014 require electricity generation facilities to be entered on the official register of electricity production plants maintained by the Ministry of Energy, Tourism and Digital Agenda.

The autonomous regions may keep their own registers of electricity generation plants they have authorized if such plants have a capacity of 50 MW or less. The registration details of these plants must be provided to the Ministry of Energy, Tourism and Digital Agenda electronically.

Solaben 2/3 and Solaben 1/6 are on the register of the autonomous region Extremadura and the Ministry of Energy, Tourism and Digital Agenda.

Solacor 1/2, PS10/20, Helioenergy 1/2 and Solnova 1/3/4 are on the register of the autonomous region of Andalusia and the Ministry of Energy, Tourism and Digital Agenda.

Helios 1/2 is on the register of the autonomous region Castilla La Mancha and the Ministry of Energy, Tourism and Digital Agenda.

To receive their facility-specific reimbursement, renewable energy facilities are required under the Electricity Act and Royal Decree 413/2014 to be listed on a new register entitled the Specific Payment System Register, *Registro de Regimen Retributivo Especifico*. Unregistered plants will only receive the pool price.

The first transitional provision of Royal Decree 413/2014 states that power plants based on renewable sources recognized under the previous economic regime, as in the case of Solaben 2/3, Solacor 1/2, PS10/20 will be automatically included in the Specific Payment System Register.

Change of Compensation System Applicable to Solar Power Plants

Royal Decree-law 9/2013 introduced a change in the payment system applicable to new and existing electricity production facilities using renewable energy sources to guarantee the financial stability of the electric system. The purpose of Royal Decree-law 9/2013, which entered into force on July 14, 2013, was to adopt a series of measures to ensure the sustainability of the electric system and to combat the shortfalls between electricity system revenues and costs, referred to as the tariff deficit.

The measures adopted were focused primarily on the following areas: (i) the legal and financial regime for existing electricity production facilities using renewable energy sources, co-generation and residual waste; (ii) the remuneration regime for transport and distribution activities; (iii) Spain's guarantee of the Securitization Fund to cover the tariff deficit; and (iv) certain aspects related to capacity payments, assumption of the cost of the subsidized tariff and a review of access charges.

Royal Decree-law 9/2013 established an entirely new remuneration system, abolishing the remuneration system based on a regulated tariff applicable to electricity production facilities using renewable energy sources (including facilities in operation at the time that Royal Decree-law 9/2013 entered into force).

Prior to the adoption of Royal Decree-law 9/2013, electricity production facilities using renewable energy sources received revenues tied to their electricity produced according to their power output. This involved receiving feed-in tariffs, in €/kWh, that were split into two components: (i) the pool price of electricity and (ii) an equivalent premium, consisting of the difference between the pool price and the set feed-in tariff for each type of plant (feed in tariff = pool price + equivalent premium). This revenue was received for a maximum annual number of hours and for a pre-determined number of years, depending on the technology used in each case. For any additional hours produced, producers received the pool price.

The repealed economic scheme was applied on a transitional basis until new provisions were approved to fully implement the new remuneration system. Settlements made after July 14, 2013 were made in accordance with the previous regime until the new implementing regulations have been adopted. However, following the implementation of these new regulations, payments made during this interim period were recalculated in accordance with the new regulations. The difference between the amounts received under the prior regime and those calculated under the new regime were deducted from the first nine settlements that followed the approval of the new implementing regulations.

Current System

According to Royal Decree 413/2014, producers receive: (i) the pool price for the power they produce and (ii) a payment based on the standard investment cost for each type of plant (without any relation whatsoever to the amount of power they generate). This payment based on investment (in €/MW of installed capacity) is supplemented (in cases of technologies with running costs in excess of the pool price) with an "operating payment" (in €/MWh produced).

The principle driving the new economic regime imposed by Royal Decree 413/2014 is that the incentives that an electricity producer receives should be equivalent to the costs that they are unable to recover on the electricity market where they compete with non-renewable technologies. The new economic regime seeks to allow a "well-run and efficient enterprise" to recover the costs of building and running a plant, plus a reasonable return on investment (project internal rate of return).

According to Royal Decree 413/2014, the remuneration for investment in respect of plants that were already in operation once the first statutory period commenced (on July 14, 2013 until December 31, 2019) is calculated as follows:

- The "standard per-MW investment value" is added to the "standard per-MW operating cost" (both updated from July 2013 with a 7.398% rate of return); i.e., what it would have cost a well-run and efficient enterprise to build, maintain and run the facility from its start-up until the time Royal Decree-law 9/2013 came into force.

- From the resulting total, the “standard per-MW total revenue valued at the electricity pool price,” earned by each type of plant from its start-up through entry into force of Royal Decree-law 9/2013 (also updated applying the 7.398% rate of return) is subtracted.

- The result (the standard per-MW investment value plus standard per-MW operating cost minus standard per-MW total revenue) is the “net investment value” i.e. the costs unrecovered by the plant owner as of July 14, 2013.

- Payments for investment to be made after Royal Decree-law 9/2013 came into force and during every year of a plant’s remaining statutory useful life are calculated by (a) adding the net investment value (calculated as explained above) to the “expected operating costs until the end of the asset’s statutory useful life;” and (b) deducting the “expected revenue on the market up to that same point in time” (in both cases, the amount would be discounted to July 2013 by applying the 7.398% rate of return). The annual amount to be received would be calculated so that it would be the same amount every year until the end of the statutory useful life.

Accordingly, under Royal Decree 413/2014, the returns received by the owners of plants in excess of 7.398%, from start-up until Royal Decree-law 9/2013 took effect, would serve to reduce the unrecovered net investment value as of July 14, 2013.

Operating payments will only be available for those facilities whose costs exceed the estimated average pool price. However, the Ministry of Energy, Tourism and Digital Agenda can cap operating payments at a maximum number of hours.

Payment Factors for Solar Power Plants

The payment system applicable for each plant is based on various criteria considered by the Ministry Energy, Tourism and Digital Agenda and includes the specific technology used, amount of power produced relative to operating costs, age of the facility and any other differentiating factor deemed necessary to consider in applications of the payment system.

Revenue Order recognizes six types of solar thermal plants: (i) parabolic trough collectors without a storage system, (ii) parabolic trough collectors with a storage system, (iii) central or tower receivers without a storage system, (iv) central or tower receivers with a storage system, (v) linear collectors and (vi) solar-biomass hybrids.

To determine the payment system applicable to each plant, the following factors are considered:

- *Net investment value*. This consists of a standard amount per MW for each type of plant, calculated by the method set out in Royal Decree 413/2014, which is the amount invested in the plant and not depreciated as of July 14, 2013.

- *Useful life of the plant*. For solar thermal plants this is 25 years.

- *Return on investment*. Considering the net asset value determined on the basis of a standard cost per MW built, an amount is set per unit of power, which enables investment costs that cannot be recovered through the pool price to be recouped over the useful life of the plant.

- *Operating remuneration*. An amount is set per unit of power and hour that, added to the pool price, enables the producer to recoup all the plant’s operating and maintenance costs. Operating expenses include the cost of land, electricity, gas and water bills, management, security, corrective and preventive maintenance, representation costs, the Spanish tax on special immovable properties, insurance, applicable generation charges and a generation tax which is equal to 7% of total revenue.

- *Maximum number of operating hours*. A maximum number of hours is set for which each plant type can receive the operating remuneration.

- *Operating threshold*. Plants must operate for more than a set number of hours per year to receive the return on investment and operating remuneration.

- *Minimum operating hours*. Plants that cross the operating threshold but operate for fewer hours than the annual minimum hours receive a lower remuneration.

On February 22, 2017, after the end of the first half-period, the Ministry of Energy, Tourism and Digital Agenda published the Updated Parameters Order, updating the remuneration parameters of the standard facilities applicable to registered power generation facilities from renewable energy sources, cogeneration and waste during the regulatory half-period running from January 1, 2017 to December 31, 2019 as set forth in the table below.

	Useful Life(1)	Return on Investment 2017 (euros/MW)	Operating Remuneration 2017 (euros/GWh)	Maximum Hours	Minimum Hours	Operating Threshold
Solaben 2	25 years	411,681	46,474	2,028	1,217	710
Solaben 3	25 years	411,681	46,474	2,028	1,217	710
Solacor 1	25 years	411,681	46,474	2,028	1,217	710
Solacor 2	25 years	411,681	46,474	2,028	1,217	710
PS 10	25 years	555,614	67,735	1,859	1,115	651
PS 20	25 years	411,953	61,918	1,859	1,115	651
Helioenergy 1	25 years	406,247	46,273	2,028	1,217	710
Helioenergy 2	25 years	406,247	46,273	2,028	1,217	710
Helios 1	25 years	411,681	46,474	2,028	1,217	710
Helios 2	25 years	411,681	46,474	2,028	1,217	710
Solnova 1	25 years	418,356	46,843	2,028	1,217	710
Solnova 3	25 years	418,356	46,843	2,028	1,217	710
Solnova 4	25 years	418,356	46,843	2,028	1,217	710
Solaben 1	25 years	408,123	46,342	2,028	1,217	710
Solaben 6	25 years	408,123	46,342	2,028	1,217	710
Seville PV	30 years	714,115	33,257	2,092	1,255	732

Note:—

(1) According to the Royal Decree 413/2014.

Regulatory Periods

Payment criteria are based on prevailing economic conditions in Spain, demand for electricity and reasonable profits for electricity generation activities and can be revised every three or six years. The Royal Decree 413/2014 establishes statutory periods of six years, with the first statutory period running from July 14, 2013 (the date of entry into force of Royal Decree-law 9/2013) to December 31, 2019. Each statutory period is divided into two statutory half-periods of three years. The first such half-period runs from July 14, 2013 to December 31, 2016.

This "statutory period" mechanism aims to set forth how and when the Ministry of Energy, Tourism and Digital Agenda is entitled to revise the different payment factors used to determine the specific remuneration to be received by the standard facilities.

At the end of each statutory half-period (three years) the Ministry of Energy, Tourism and Digital Agenda may revise (i) the electricity market price estimates and (ii) the adjustment value for electricity market price deviations in the preceding statutory half-period.

Unless reviewed, payment criteria will be considered to be extended for the subsequent regulatory period.

Reasonable Rate of Return

Article 14 of the Electricity Act provides that a reasonable return on investment is calculated on the basis of the average pre-tax yield of Spanish government 10-year bonds on the secondary market.

For plants that are already in operation, the reasonable return over the regulatory life of the plants is based on the average pre-tax yield on Spanish government 10-year bonds on the secondary market for the preceding 24 months, plus 300 basis points.

Annex III of the Revenue Order specifies that the 10-year average yield for the 10-year bond is 4.398%, which, increased by 300 bps, results in 7.398% per annum.

Under no circumstances will amounts received by producers for electricity generated before July 14, 2013 be required to be returned or reimbursed under the new system.

Before the start of a new regulatory period, a revised reasonable return can be established for each plant type, calculated as the average yield on Spanish government 10-year bonds on the secondary market in the 24 months through the month of May preceding the new regulatory period, plus a spread.

This spread is based on the following criteria:

- Appropriate profit for this specific type of renewable electricity generation and electricity generation as a whole, considering the financial condition of the Spanish electricity system and Spanish prevailing economic conditions; and

- Borrowing costs for electricity generation companies using renewable energy sources with regulated payment systems, which are efficient and well run, within Europe.

The next regulatory period will begin on January 1, 2020.

Funding the Tariff Deficit

The Electricity Act also states that from January 1, 2014, tariff deficit amounts would no longer be paid for, as they had been previously, by the five major Spanish utilities. Instead, they will be paid by the companies that receive "regulated payments," including distributors, transportation companies, producers of electricity from renewable plants, companies receiving capacity payments and others. Each of these entities will temporarily fund the tariff deficit in proportion to the costs that they represent for the electricity system in a given year and can recover these contributions in the following five years, plus interest at a market rate.

According to the Electricity Act, tariff deficit cannot exceed 2% of the estimated system revenues for each year. Furthermore, the accumulated debt due to previous years' deficit cannot exceed 5% of the estimated system revenues for that period. If these thresholds are exceeded, the Spanish government is forced to review the access fees so that the system revenues increase accordingly.

Access Fee

Royal Decree-law 14/2010 was passed in order to eliminate the shortfalls between electricity system revenues and costs, referred to as the tariff deficit in the electricity sector.

The First Transitional Provision of Royal Decree-law 14/2010 provided that the owners of electricity production facilities pay a fee for access to the grid to the transmission and distribution companies (this access previously having been provided at no cost) from January 1, 2011. During the interim period, the access fee payable is: (i) calculated at €0.5 per MWh delivered to the network or (ii) any other amount that the Ministry of Energy, Tourism and Digital Agenda establishes.

Royal Decree 1544/2011 implemented the First Transitional Provision of Royal Decree 14/2010 and confirmed the interim access fee imposed on electricity producers (€0.5 per MWh), subject to the adoption of a final method for calculating the access fee.

Electricity Sales Tax

On December 27, 2012, the Spanish Parliament approved Law 15/2012, which became effective on January 1, 2013. The aim of Law 15/2012 is to try to combat the problem of the so-called tariff deficit, which reached approximately €28 billion as of December 2013.

Law 15/2012, as amended, provides for an electricity sales tax which is levied on activities related to electricity production. The tax is triggered by the sale of electricity and affects ordinary energy producers and those generating power from renewable sources. The tax, a flat rate of 7%, is levied on the total income received from the power produced at each of the installations, which means that every calendar year, solar power plants will be required to pay 7% of the total amount which they are entitled to receive for production and incorporation into the electricity system of electric power, measured as the net output generated.

Tax Incentive of Accelerated Depreciation of New Assets

Under provisions of the Spanish Corporate Income Tax Act, tax-free depreciation is permitted on investments in new material assets and investment properties used for economic activities acquired between January 1, 2009 and March 31, 2012. Taxpayers who made investments during such period and have amounts pending to be deducted for this concept may apply such amounts with certain limitations.

Taxpayers who made or will make investments from March 31, 2012 through March 31, 2015 in new material assets and investment properties used for economic activities are permitted to take accelerated depreciation for those assets subject to certain limitations. The accelerated depreciation is permitted if:

- 40% of the tax base before the amortization or depreciation and before the offset of tax loss carryforwards for taxpayers (subject to requirements to keep up employment levels); or

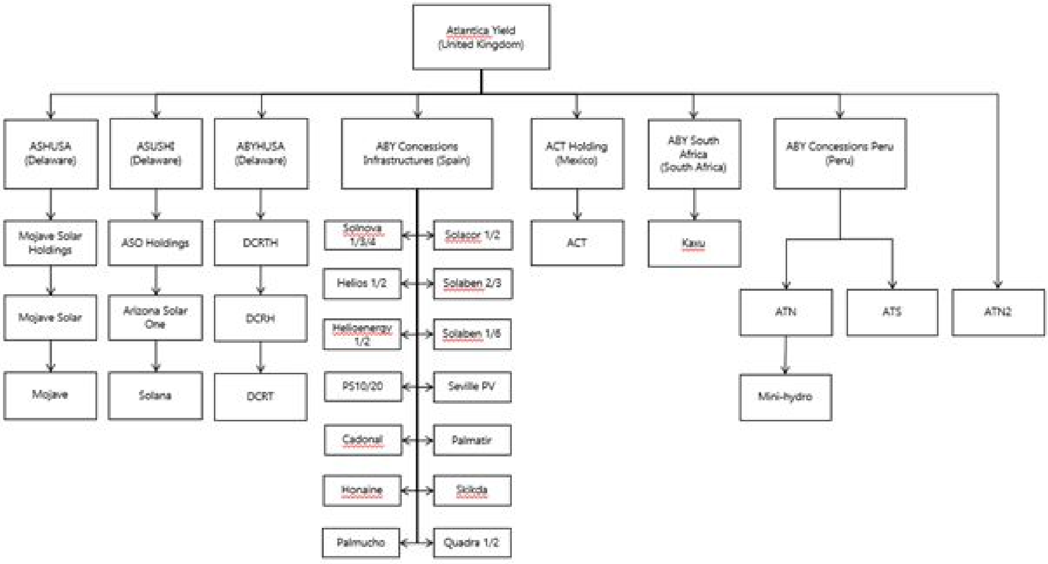
- 20% of the tax base before the amortization or depreciation and before the offset of tax loss carryforwards for taxpayers (without employment requirements).

Most of the investment in our Spanish assets was undertaken within the regime that applied between January 1, 2009 and March 31, 2012.

These limitations do not apply in respect of companies that meet the requirements set forth in article 108.1 of the Spanish Corporate Income Tax Act related to the special rules for enterprises of a reduced size.

C. Organizational Structure

The following summary chart sets forth our ownership structure as of the date of this annual report:



Notes:—

(1) ACIN directly holds one share in each of ABY Concessions Peru S.A., ATN S.A. and ATS S.A.
(2) Atlantica Yield plc directly holds one share in Palmucho and 10 shares in each of Quadra 1 and Quadra 2.
(3) 30% is held by Itochu, a Japanese company.
(4) 13% is held by JGC, a Japanese company.
(5) AEC holds 49% of Honaine and Skikda. Valoriza Agua, S.L. holds 25.5% of Honaine and 16.9% of Skikda.
(6) 20% of Seville PV is held by Instituto de Diversificacion y Ahorro de la Energia, or IDEA, a Spanish state-owned company.
(7) ATN holds a 25% stake in ATN2.

D. Property, Plant and Equipment

See “Item 4.B—Business Overview.”

ITEM 4A.UNRESOLVED STAFF COMMENTS

Not applicable.

ITEM 5. OPERATING AND FINANCIAL REVIEW AND PROSPECTS

The following discussion should be read together with, and is qualified in its entirety by reference to, our Annual Consolidated Financial Statements. The following discussion contains forward-looking statements that reflect our plans, estimates and beliefs, which are based on assumptions we believe to be reasonable. Our actual results could differ materially from those discussed in these forward-looking statements as a result of various factors, including those set forth under "Item 3.D—Risk Factors" and elsewhere in this annual report.

A. Operating Results

Overview

We are a total return company that owns, manages, and acquires renewable energy, efficient natural gas (previously named "conventional") power, electric transmission lines and water assets, focused on North America (the United States and Mexico), South America (Peru, Chile and Uruguay) and EMEA (Spain, Algeria and South Africa). We intend to expand, maintaining North America, South America and Europe as our core geographies.

As of the date of this annual report, we own or have interests in 22 assets, comprising 1,446 MW of renewable energy generation, 300 MW of efficient natural gas (previously named "conventional") power generation, 10.5 M ft3 per day of water desalination and 1,099 miles of electric transmission lines. All of our assets have contracted revenues (regulated revenues in the case of our Spanish assets) with low-risk off-takers and collectively have a weighted average remaining contract life of approximately 19 years as of December 31, 2017. Most of the assets we own have a project-finance agreement in place.

We intend to take advantage of favorable trends in the power generation and electric transmission sectors globally, including energy scarcity and a focus on the reduction of carbon emissions. To that end, we believe that our cash flow profile, coupled with our scale, diversity and low-cost business model, offers us a lower cost of capital than that of a traditional engineering and construction company or independent power producer and provides us with a significant competitive advantage with which to execute our growth strategy.

We are focused on high-quality, newly-constructed and long-life facilities that have contracts with creditworthy counterparties that we expect will produce stable, long-term cash flows. We will seek to grow our cash available for distribution and our dividend to shareholders through organic growth and by acquiring new contracted assets from AAGES, from Abengoa, from third parties and from potential new future partners.

We have in place an exclusive agreement with Abengoa, which we refer to as the Abengoa ROFO Agreement, which provides us with a right of first offer on any proposed sale, transfer or other disposition of any of Abengoa's contracted renewable energy, efficient natural gas power, electric transmission or water assets in operation and located in the United States, Canada, Mexico, Chile, Peru, Uruguay, Brazil, Colombia and the European Union, as well as four assets in selected countries in Africa, the Middle East and Asia. See "Item 4.B—Business Overview—Our Growth Strategy" and "Item 7.B—Related Party Transactions—Abengoa Right of First Offer."

In addition, on March 5, 2018, we entered into a ROFO agreement with AAGES which we refer to as the AAGES ROFO Agreement, that will become effective upon completion of the Share Sale, for which all conditions precedent have been satisfied and for which the parties have commenced the process for the transfer of our shares, which we expect to close in the upcoming days. AAGES is the joint venture formed by Algonquin and Abengoa to develop and invest renewable energy and water assets. The AAGES ROFO Agreement provides us with a right of first offer on any proposed sale, transfer or other disposition of AAGES ROFO Assets. See "Item 4.B—Business Overview—Our Growth Strategy" and "Item 7.B—Related Party Transactions—AAGES Right of First Offer."

Additionally, we plan to sign similar agreements or enter into partnerships with other developers or asset owners to acquire assets in operation. We may also invest directly or through investment vehicles with partners in assets under development or construction, ensuring that such investments are always a small part of our total investments. Finally, we also expect to acquire assets from third parties leveraging the local presence and network we have in the geographies and sectors in which we operate.

With this business model, our objective is to pay a consistent and growing cash dividend to shareholders that is sustainable on a long-term basis. We expect to distribute a significant percentage of our cash available for distribution as cash dividends and we will seek to increase such cash dividends over time through organic growth and as we acquire assets with characteristics similar to those in our current portfolio. Pursuant to our cash dividend policy, we intend to pay a cash dividend each quarter to holders of our shares.

Based on the acquisition opportunities available to us, we believe that we will have the opportunity to grow our cash available for distribution in a manner that would allow us to increase our cash dividends per share over time. Prospective investors should read "Item 5.B—Liquidity and Capital Resources—Cash dividends to investors" and "Item 3.D—Risk Factors," including the risks and uncertainties related to our forecasted results, acquisition opportunities and growth plan, in their entirety.

Acquisitions

First Dropdown Assets

On November 18, 2014, we completed the acquisition of a 74% stake in Solacor 1/2, a 100 MW solar power plant in Spain; on December 4, 2014, we completed the acquisition of PS10/20, a 100 MW solar power complex in Spain; and on December 29, 2014, we completed the acquisition of Cadonal, an on-shore wind farm located in Uruguay with a capacity of 50 MW. The total aggregate consideration for the First Dropdown Assets was $312 million.

Second Dropdown Assets

On February 3, 2015, we completed the acquisition of a 25.5% stake in Honaine and a 34.2% stake in Skikda, which are two water desalination plants in Algeria with an aggregate capacity of 10.5 M ft3 per day. Revenues from these assets are indexed to U.S. dollars and payable in local currency. On February 23, 2015, we completed the acquisition of a 29.6% stake in Helioenergy 1/2, a 100 MW solar complex located in Spain. All these assets were acquired from Abengoa under the Abengoa ROFO Agreement. The total aggregate consideration for the Second Dropdown Assets was $94 million.

Third Dropdown Assets

On May 13, 2015, we completed the acquisition of Helios 1/2, a 100 MW solar complex located in Spain. On May 14, 2015, we completed the acquisition of Solnova 1/3/4, a 150 MW solar complex located in Spain. On May 25, 2015, we completed the acquisition of the remaining 70.4% stake in Helioenergy 1/2, a 100 MW solar complex in Spain. On July 30, 2015, we completed the acquisition of Kaxu, a 100 MW solar plant in South Africa. The total aggregate consideration for the Third Dropdown Assets was $682 million.

Fourth Dropdown Assets

On June 25, 2015, we completed the acquisition of ATN2, an 81-mile transmission line in Peru. On September 30, 2015, we completed the acquisition of Solaben 1/6, a 100 MW solar complex in Spain. These assets were acquired from Abengoa under the Abengoa ROFO Agreement. In addition, on January 7, 2016, we completed the acquisition from JGC of a 13% in Solacor 1/2, a 100 MW solar complex in Spain where we already owned a 74% stake. The total aggregate consideration agreed for the Fourth Dropdown Assets was $378 million, of which $18.8 million was paid during 2016. As of December 31, 2017, there is no pending balance.

Subsequent acquisitions

Additionally, on August 3, 2016, we completed the acquisition of an 80% stake in Seville PV from Abengoa, a 1 MW solar photovoltaic plant in Spain for a total consideration of $3.2 million.

On February 28, 2017, we completed the acquisition of a 12.5% interest in a 114-mile transmission line in the United States, from Abengoa. The asset will receive a FERC-regulated rate of return, and is currently under development, with COD expected in 2020. We expect our total investment to be up to $10 million in the coming three years including an initial amount invested at cost. We also hold certain rights to acquire an additional 12.5% interest in the same project.

On February 28, 2018, we completed the acquisition of a 4 MW mini-hydroelectric power plant in Peru for $9 million. The plant reached COD in 2012. It has a fixed-price concession agreement denominated in U.S. dollars with the Ministry of Energy of Peru and the price is adjusted annually in accordance with the U.S. Consumer Price Index. We financed the acquisition with cash on hand.

Our Operations

We own a diversified portfolio of contracted assets across the renewable energy, efficient natural gas (previously named “conventional”) power, electric transmission line and water sectors in North America (the United States and Mexico), South America (Peru, Chile and Uruguay) and EMEA (Spain, Algeria and South Africa). We intend to expand, maintaining North America, South America and Europe as our core geographies. Our portfolio consists of 14 renewable energy assets, a natural gas-fired cogeneration facility, several electric transmission lines and minority stakes in two water desalination plants, all of which are fully operational. All of our assets have contracted revenues (regulated revenues in the case of our Spanish assets) with low-risk offtakers and collectively have a weighted average remaining contract life of approximately 19 years as of December 31, 2017. We expect that the majority of our cash available for distribution over the next three years will be in U.S. dollars, indexed to the U.S. dollar or in euros. We intend to maintain a ratio of over 80% of our cash available for distribution denominated in U.S. dollars or euros and to hedge euros for the upcoming 24 months on a rolling basis. Approximately 93% of our project-level debt is hedged against changes in interest rates through an underlying fixed rate on the debt instrument or through interest rate swaps, caps or similar hedging instruments.

Results of Operations

Revenue by geography

Our revenue and Further Adjusted EBITDA by geography and business sector for the years ended December 31, 2017, 2016 and 2015 are set forth in the following tables:

	Year ended December 31,					
	2017		2016		2015	
	$ in millions	% of revenue	$ in millions	% of revenue	$ in millions	% of revenue
North America	$ 332.7	33.0%	$ 337.0	34.7%	$ 328.1	41.5%
South America	120.8	12.0%	118.8	12.2%	112.5	14.2%
EMEA	554.9	55.0%	516.0	53.1%	350.3	44.3%
Total revenue	**$ 1,008.4**	**100%**	**$ 971.8**	**100%**	**$ 790.9**	**100%**

Revenue by business sector

	Year ended December 31,					
	2017		2016		2015	
	$ in millions	% of revenue	$ in millions	% of revenue	$ in millions	% of revenue
Renewable Energy	$ 767.2	76.1%	$ 724.3	74.5%	$ 543.0	68.7%
Efficient Natural Gas Power	119.8	11.9%	128.1	13.2%	138.7	17.5%
Electric Transmission	95.1	9.4%	95.1	9.8%	86.4	10.9%
Water	26.3	2.6%	24.3	2.5%	22.8	2.9%
Total revenue	**$ 1,008.4**	**100%**	**$ 971.8**	**100%**	**$ 790.9**	**100%**

Further Adjusted EBITDA by geography

	Year ended December 31,					
	2017		2016		2015	
	$ in millions	% of revenue	$ in millions	% of revenue	$ in millions	% of revenue
North America	$ 282.3	84.9%	$ 284.7	84.5%	$ 279.6	85.2%
South America	108.8	90.0%	124.6	104.9%	110.9	98.6%
EMEA	388.2	70.0%	354.0	68.6%	233.7	66.7%
Further Adjusted EBITDA(1)	**$ 779.3**	**77.3%**	**$ 763.3**	**78.5%**	**$ 624.2**	**78.9%**

Further Adjusted EBITDA by business sector

	Year ended December 31,					
	2017		2016		2015	
	$ in millions	% of revenue	$ in millions	% of revenue	$ in millions	% of revenue
Renewable Energy	$ 569.2	74.2%	$ 538.4	74.3%	$ 414.0	76.2%
Efficient Natural Gas Power	106.1	88.6%	106.5	83.2%	107.7	77.6%
Electric Transmission	87.7	92.2%	104.8	110.2%	89.0	103.1%
Water	16.3	62.0%	13.6	56.0%	13.5	59.6%
Further Adjusted EBITDA(1)	**$ 779.3**	**77.3%**	**$ 763.3**	**78.5%**	**$ 624.2**	**78.9%**

Note:—

(1) Further Adjusted EBITDA is calculated as profit/(loss) for the year attributable to the parent company, after adding back loss/(profit) attributable to non-controlling interest from continued operations, income tax, share of profit/(loss) of associates carried under the equity method, finance expense net, depreciation, amortization and impairment charges of entities included in the Annual Consolidated Financial Statements, and dividends received from our preferred equity investment in ACBH. Further Adjusted EBITDA for the year ended December 31, 2016 and for the first quarter of 2017 includes compensation received from Abengoa in lieu of ACBH dividends. Further Adjusted EBITDA is not a measure of performance under IFRS as issued by the IASB and you should not consider Further Adjusted EBITDA as an alternative to operating income or profits or as a measure of our operating performance, cash flows from operating, investing and financing activities or as a measure of our ability to meet our cash needs or any other measures of performance under generally accepted accounting principles. We believe that Further Adjusted EBITDA is a useful indicator of our ability to incur and service our indebtedness and can assist securities analysts, investors and other parties to evaluate us. Further Adjusted EBITDA and similar measures are used by different companies for different purposes and are often calculated in ways that reflect the circumstances of those companies. Further Adjusted EBITDA may not be indicative of our historical operating results, nor is it meant to be predictive of potential future results. See "Presentation of Financial Information—Non-GAAP Financial Measures."

Factors Affecting the Comparability of Our Results of Operations

Acquisitions

On February 3, 2015, we completed the acquisition of a 25.5% stake in Honaine and a 34.17% stake in Skikda, which are two water desalination plants in Algeria with an aggregate capacity of 10.5 M ft3 per day. On February 23, 2015 we completed the acquisition of a 29.6% stake in Helioenergy 1/2, a 100 MW solar complex located in Spain.

On May 13, 2015, we completed the acquisition of Helios 1/2, a 100 MW solar complex located in Spain from Abengoa under the Abengoa ROFO Agreement.

On May 14, 2015, we completed the acquisition of Solnova 1/3/4, a 150 MW solar complex located in Spain from Abengoa under the Abengoa ROFO Agreement.

On May 25, 2015, we completed the acquisition of the remaining 70.4% stake in Helioenergy 1/2, a 100 MW solar complex in Spain from Abengoa under the Abengoa ROFO Agreement.

On June 25, 2015, we completed the acquisition of 40% equity stake of ATN2, an 81-mile transmission line in Peru from Abengoa under the Abengoa ROFO Agreement. We also acquired the remaining 60% equity stake owned by Sigma, a third-party financial investor, in ATN2.

On July 30, 2015, we completed the acquisition of a 51% stake in Kaxu a 100 MW solar plant in South Africa.

On September 30, 2015, we completed the acquisition of Solaben 1/6 from Abengoa.

On August 3, 2016, we completed the acquisition of an 80% stake in Seville PV from Abengoa, a 1 MW solar photovoltaic plant in Spain.

On February 28, 2017, we completed the acquisition of a 12.5% interest in a 114-mile transmission line in the U.S. from Abengoa at cost. We expect our total investment to be up to $10 million in the coming three years, including the initial amount invested at cost.

The results of operations of each acquisition have been consolidated since the date of their respective acquisition except for Honaine, which is recorded under the equity method, and Helioenergy 1/2, which was recorded under the equity method from February 23, 2015, the date we acquired a 30% ownership stake in the asset, until May 25, 2015, the date we gained control over the asset. Helioenergy 1/2 has been fully consolidated since May 25, 2015.

These acquisitions, and any other acquisitions we may make from time to time, will affect the comparability of our results of operations.

Exchangeable Preferred Equity Investment in Abengoa Concessões Brasil Holding

Since our IPO until 2017 we held an exchangeable preferred equity investment in ACBH, a subsidiary holding company of Abengoa engaged in the development, construction, investment and management of contracted concessions in Brazil, comprised mostly of transmission lines, some of which were in operation and some under construction. Pursuant to the amended and restated shareholders' agreement dated June 30, 2015, entered into among us, ACBH and the ordinary shareholders of ACBH, we had the right to receive a preferred dividend of $18.4 million per year during the five-year period commencing on July 1, 2014, which we received quarterly since the third quarter of 2014 until the fourth quarter of 2015.

On January 29, 2016, Abengoa informed us that several of its indirect subsidiaries of Abengoa in Brazil, including ACBH, had initiated an insolvency procedure under Brazilian law ("*reorganizaçao judiciaria*"), as a "*Pedido de processamento conjunto*," which means the substantial consolidation of the three main subsidiaries of Abengoa in Brazil, including ACBH. In April 2016, Abengoa presented a consolidated restructuring plan in the Brazilian Court, including ACBH and two other subsidiaries.

Pursuant to the terms of the agreements entered into between us, Abengoa and ACBH under certain circumstances, if we did not receive the preferred equity dividend from ACBH, we could defer a portion of the dividend payable by us to Abengoa as our shareholder, in an amount equal to that shortfall. See "Item 4.B—Business Overview—Our Operations—Exchangeable Preferred Equity Investment in Abengoa Concessões Brasil Holding." However, any such deferral would be made only if and to the extent that the Abengoa subsidiary holding Abengoa's shares in us continued to be a shareholder of ours as of the relevant date. We retained dividends payable to Abengoa in 2015, 2016 and 2017.

In the third quarter of 2016, we signed an agreement with Abengoa relating to the ACBH preferred equity investment among other things with the following main consequences:

• Abengoa acknowledged it failed to fulfill its obligations under the agreements related to the preferred equity investment in ACBH and, as a result, we were recognized as the legal owner of the dividends that we retained from Abengoa and these amounts were recorded as Further Adjusted EBITDA in 2017 ($10.4 million) and in 2016 ($28.0 million).

• Abengoa recognized a non-contingent credit corresponding to the guarantee provided by Abengoa regarding the preferred equity investment in ACBH, subject to restructuring. On October 25, 2016, we signed Abengoa's restructuring agreement and accepted, subject to implementation of the restructuring, to receive 30% of the amount owed to us in the form of tradable notes to be issued by Abengoa (the "Restructured Debt"). The remaining 70% owned to us was agreed to be received in the form of equity in Abengoa.

• The Restructured Debt was converted into senior status following our participation in Abengoa's issuance of asset-backed notes, or New Money 1 Tradable Notes. We subsequently sold New Money 1 Tradable Notes in early April 2017.

• Since we received the Restructured Debt and Abengoa equity, we waived, as agreed, all our rights under the ACBH agreements, including our right to further retain dividends payable to Abengoa. As a result, in March 2017, we wrote off the accounting value of the ACBH instrument, which amounted to $30.5 million as of December 31, 2016. We no longer own any shares in ACBH. We have sold most of the debt and equity instruments we received from Abengoa and we do not expect material additional value from the ACBH preferred equity investment.

Impairment

As a result of the legal situation of ACBH since 2016 referred to above, the results for the year ended December 31, 2016 were impacted by the impairment of our preferred equity investment in ACBH of $22.1 million and the results for the year ended December 31, 2015 were impacted by the impairment of our preferred equity investment in ACBH of $210.4 million. We did not record any additional impairment in 2017 since we wrote-off the accounting value of this instrument following the agreement reached with Abengoa as "Other financial expense." See "Item 4B.—Business Overview—Exchangeable Preferred Equity Investment in Abengoa Concessões Brasil Holding."

In addition, in the fourth quarter of 2016, we recorded an impairment of $20.3 million in our wind assets in Uruguay. See Note 6 of our Annual Consolidated Financial Statements.

Change of ownership under Section 382 of the Internal Revenue Code

Under section 382 of the IRC, an "ownership change" would occur if our direct and indirect "5-percent shareholders," as defined under Section 382 of the IRC, collectively increased their ownership in us by more than 50 percentage points over a rolling three-year period. As a result of Abengoa's restructuring and the change in its shareholders' base, we have experienced a change of ownership has defined under section 382 of the IRC, which causes an annual limitation on the use of the pre-ownership change U.S. NOLs generated by our U.S. solar assets equal to the equity value of the corporation immediately before the ownership change, multiplied by the long-term tax-exempt rate for the month in which the ownership change occurs, and increased by a certain portion of any "built-in-gains." In addition, because we have recorded tax credits for the US tax losses carryforwards in the past, the limitation to our ability to use net operating loss carryforwards in the United States has resulted in writing off tax credits previously recognized for an amount of $96 million. This one-time income tax expense did not have any cash impact in 2017 and we continue to expect not to pay income taxes in our U.S. solar assets for at least 10 years.

U.S. Tax Reform

As discussed in note 18 of the Annual Consolidated Financial Statements, in December 2017, the TCJA was enacted in the United States. The measures adopted include, among other measures, a decrease in the corporate tax rate from 35.0% to 21.0% effective 1st of January 2018. We therefore adjusted the deferred tax assets and liabilities of its U.S. entities using the new enacted corporate tax rate as of December 31, 2017, resulting in a one-time non-cash income tax expense of $19 million recorded in the consolidated income statement for the year ended December 31, 2017.

Factors Affecting our Results of Operations

Regulation

We operate in a significant number of regulated markets. The degree of regulation to which our activities are subject varies by country. In a number of the countries in which we operate, regulation is carried out by national regulatory authorities. In some countries, such as the United States and, to a certain degree, Spain, there are various additional layers of regulation at the state, regional and/or local levels. In such countries, the scope, nature, and extent of regulation may differ among the various states, regions and/or localities.

While we believe the requisite authorizations, permits, and approvals for our existing activities have been obtained and that our activities are operated in substantial compliance with applicable laws and regulations, we remain subject to a varied and complex body of laws and regulations that both public officials and private parties may seek to enforce. See "Item 4.B—Business Overview—Regulation" for a description of the primary industry-related regulations applicable to our activities in the United States and Spain and currently in force in certain of the principal markets in which we operate.

Power purchase agreements and other contracted revenue agreements

As of December 31, 2017, the average remaining life of our PPAs, concessions and contracted revenue agreements was approximately 19 years. We believe that the average life of our PPAs and contracted revenue agreements is a significant indicator of our forecasted revenue streams and the growth of our business. Contracted assets and concessions consist of long-term projects awarded to and undertaken by us (in conjunction with other companies or on an exclusive basis) typically over a term of 20 to 30 years. Upon expiration of our PPAs and contracted revenue agreements and in order to maintain and grow our business, we must obtain extensions to these agreements or secure new agreements to replace them as they expire. Under most of our PPAs and concessions, there is an established price structure that provides us with price adjustment mechanisms that partially protect us against inflation. See "Item 4.B—Business Overview—Our Operations."

Tax incentives in the United States for renewable energy assets

U.S. federal, state and local governments have established several incentives and financial mechanisms to reduce the cost of renewable energy and spur the development of energy from renewable, non-carbon–based, sources. Some of the major tax incentives applied in our projects are, among others, ITC, Cash Grant in Lieu of ITC, MACRS, and Loan Guarantee Program.

We do not expect Solana or Mojave to pay U.S. federal income tax in the next 10 years due to the relevant NOLs and NOL carryforwards generated by the application of the aforementioned tax incentives established in the United States, in particular MACRS accelerated depreciation.

Tax accelerated depreciation for Spanish new assets

For investments in new material assets and investment properties used for economic activities acquired in the tax periods commencing in 2009 up to March 31, 2012, tax free depreciation is allowed. Due to this special regime, Solaben 2/3, Solacor 1/2, PS10/20, Helios 1/2, Helioenergy 1/2 and Solnova 1/3/4 do not expect to pay taxes in the next 10 years.

Specific corporate income tax rules in Mexico

Our project in Mexico, ACT, must pay Mexican corporate income tax on its worldwide income. The general taxable income is calculated in a similar way to the other jurisdictions in which our assets are located; however, the Mexican corporate income tax provides for specific inflationary adjustments on monetary assets and liabilities.

Notwithstanding the above, the project is not expected to pay significant income taxes until 2019 or 2020 due to the NOL carryforwards generated during the construction phase.

Project debt

We finance our contracted assets primarily through project debt issued by financial institutions. Consequently, a significant part of our business is capital-intensive, and our assets are highly leveraged. See "Item 5.B—Liquidity and Capital Resources—Capital expenditures."

Interest rates

We incur significant indebtedness at the corporate level and in our assets. The interest rate risk arises mainly from indebtedness with variable interest rates.

Most of our debt consists of project debt. As of December 31, 2017, approximately 93% of our project debt has either fixed interest rates or has been hedged with swaps or caps.

Regarding our corporate debt, in November 2014, we incurred indebtedness at the corporate level through the issuance of the 2019 Notes, which have a fixed interest rate of 7.00% See "Item 5.B—Liquidity and Capital Resources—Financing Arrangements—2019 Notes."

On December 3, 2014, we entered into a revolving credit facility of up to $125 million with HSBC Bank plc, as administrative agent, HSBC Corporate Trust Company (UK) Limited, as collateral agent and Banco Santander, S.A., Bank of America, N.A., Citigroup Global Markets Limited, HSBC Bank plc and RBC Capital Markets as joint lead arrangers and joint bookrunners. We refer to the $125 million tranche of the Revolving Credit Facility as Tranche A. On June 26, 2015, we amended and restated our Revolving Credit Facility to include an additional revolving credit facility of up to $290 million, or "Tranche B," which we fully repaid and cancelled in February 2017 prior to its maturity in December 2017.

Loans under Tranche A of the Revolving Credit Facility accrue interest at a rate per annum equal to: (A) for Eurodollar rate loans, LIBOR plus 2.75% and (B) for base rate loans, the highest of (i) the rate per annum equal to the weighted average of the rates on overnight U.S. Federal funds transactions with members of the U.S. Federal Reserve System arranged by U.S. Federal funds brokers on such day plus 1/2 of 1.00%, (ii) the U.S. prime rate and (iii) LIBOR plus 1.00%, in any case, plus 1.75%. The interest rate of the Revolving Credit Facility is hedged by an interest rate swap contracted with HSBC Bank with maturity date December 24, 2018, which fixes the interest rate at 4.7%. As of December 31, 2017, the amount drawn under Tranche A of the Revolving Credit Facility amounted to $54 million and $71 million of the Revolving Credit Facility was available.

On February 10, 2017, we signed a Note Issuance Facility, a senior secured note facility with a group of funds managed by Westbourne Capital as purchasers of the notes issued thereunder for a total amount of € 275 million (approximately $330 million), with three series of notes. Series 1 notes worth €92 million mature in 2022; series 2 notes worth €91.5 million mature in 2023; and series 3 notes worth €91.5 million mature in 2024. Interest on all three series accrues at a rate per annum equal to the sum of 3-month EURIBOR plus 4.90%. The proceeds of the Note Issuance Facility were used for the repayment and termination of Tranche B under our Revolving Credit Facility. We fully hedged the Note Issuance Facility with a swap that fixed the interest rate at 5.5%.

In July 2017, we signed a credit facility with a local bank for up to €10 million (approximately $12.0 million) which is available in euros or U.S. dollars. Amounts drawn under the credit facility accrue interest at a rate per annum equal to EURIBOR plus 2.25% or LIBOR plus 2.25%, depending on the currency. The credit facility has a maturity date of July 20, 2018. As of December 31, 2017, we drew down the credit facility in full and used the entire proceeds to prepay part of Tranche A of the Revolving Credit Facility.

To mitigate the interest rate risk, we primarily use long-term interest rate swaps and interest rate options which, in exchange for a fee, offer protection against a rise in interest rates. We estimate that approximately 93% of our total interest risk exposure is fixed or hedged. Nevertheless, our results of operations can be affected by changes in interest rates with respect to the unhedged portion of our indebtedness that bears interest at floating rates, which typically bears a spread over EURIBOR or LIBOR.

Exchange rates

Our functional currency is the U.S. dollar, as most of our revenues and expenses are denominated or linked to U.S. dollars. All our companies located in North America, South America and Algeria have their PPAs, or concessional agreements, and financing contracts signed in, or indexed to, U.S. dollars. Our solar power plants in Spain have their revenues and expenses denominated in euros. Revenues and expenses of Kaxu, our solar plant in South Africa, are denominated in South African rand. While fluctuations in the value of the euro and the South African rand may affect our operating results, we hedge cash distributions from our Spanish assets. Our strategy is to hedge the exchange rate for the distributions from our Spanish assets after deducting euro-denominated interest payments and euro-denominated general and administrative expenses. Through currency options, we hedge 100% of the net euro net exposure for the next 12 months and 75% of the net euro net exposure for the following 12 months.

Impacts associated with fluctuations in foreign currency are discussed in more detail under “Item 11—Quantitative and Qualitative Disclosure about Market Risk—Foreign Exchange Rate Risk” in this Annual Report on Form 20-F. In subsidiaries with functional currency other than the U.S. dollar, assets and liabilities are translated into U.S. dollars using end-of-period exchange rates; revenue, expenses and cash flows are translated using average rates of exchange. Fluctuations in the value of foreign currencies (the euro and the South African rand) in relation to the U.S. dollar may affect our operating results.

The following table sets forth, for the periods indicated, the Noon Buying Rate certified by the Federal Reserve Bank of New York expressed in U.S. dollar per €1.00 and U.S. dollar per R1.00 and published by the Federal Reserve. The Noon Buying Rate refers to the exchange for euro, expressed in U.S. dollars per euro, euro, and to the exchange for South African rand, expressed in U.S. dollars per South African rand, in the City of New York for cable transfers payable in foreign currencies as certified by the Federal Reserve Bank of New York for customs purposes. The rates may differ from the actual rates used in the preparation of the Annual Consolidated Financial Statements and other financial information appearing in this annual report. We do not represent that the U.S. dollar amounts referred to below could be or could have been converted into euro at any particular rate indicated or any other rate.

The average rate of the Noon Buying Rate means the average rates for the euro and South African rand on the last day reported of each month during the relevant period.

The Federal Reserve Bank of New York Noon Buying Rate of the euro on March 2, 2018 was $1.2314 per €1.00.

	U.S. Dollar per €1.00			
	High	**Low**	**Average**	**Period End**
Year				
2013	1.3816	1.2774	1.3303	1.3779
2014	1.3927	1.2101	1.3296	1.2101
2015	1.2015	1.0524	1.1096	1.0859
2016	1.1516	1.0375	1.0552	1.0552
2017	1.2488	1.0416	1.1359	1.2022
Month				
July 2017	1.1826	1.1336	1.1530	1.1826
August 2017	1.2025	1.1703	1.1813	1.1894
September 2017	1.2041	1.1747	1.1913	1.1813
October 2017	1.1847	1.1580	1.1755	1.1648
November 2017	1.1936	1.1577	1.1743	1.1898
December 2017	1.2022	1.1725	1.1836	1.2022
January 2018	1.2488	1.1922	1.2197	1.2428
February 2018	1.2482	1.2211	1.2340	1.2211
March 2018 (through March 2, 2018)	1.2314	1.2216	1.2265	1.2314

The Federal Reserve Bank of New York Noon Buying Rate of the South African rand on March 2, 2018 was 11.9575 per R1.00.

	U.S. Dollar per R1.00			
	High	**Low**	**Average**	**Period End**
Year				
2013	10.4925	8.4927	9.6436	10.4850
2014	11.7455	10.2990	10.8420	11.5425
2015	15.7510	11.2705	12.7645	15.4660
2016	16.8845	13.2725	14.6821	13.7000
2017	14.4925	12.3000	13.2957	12.3750
Month				
July 2017	13.5950	12.9050	13.1504	13.2225
August 2017	13.4700	12.9800	13.2272	12.9925
September 2017	13.5375	12.7625	13.1698	13.5100
October 2017	14.1725	13.2600	13.6975	14.1325
November 2017	14.4925	13.5950	14.0428	13.6425
December 2017	13.7225	12.3000	13.0918	12.3750
January 2018	12.4950	11.8525	12.1951	11.8900
February 2018	12.1325	11.5500	11.8216	11.7800
March 2018 (through March 2, 2018)	11.9575	11.8825	11.9200	11.9575

Apart from the impact of translation differences described above, the exposure of our income statement to fluctuations of foreign currencies is limited, as the financing of projects is typically denominated in the same currency as that of the contracted revenue agreement. This policy seeks to ensure that the main revenue and expenses in foreign companies are denominated in the same currency, limiting our risk of foreign exchange differences in our financial results.

Key Performance Indicators

In addition to the factors described above, we closely monitor the following key drivers of our business sectors' performance to plan for our needs, and to adjust our expectations, financial budgets and forecasts appropriately.

	As of and for the year ended December 31,		
	2017	**2016**	**2015**
Renewable Energy			
MW in operation[1]	1,442	1,442	1,441
GWh produced	3,167	3,087	2,536
Efficient Natural Gas Power			
MW in operation[1]	300	300	300
GWh produced[2]	2,372	2,416	2,465
Availability (%)[3]	100.5%	99.1%	101.7%
Electric Transmission			
Miles in operation	1,099	1,099	1,099
Availability (%)[3]	97.9%	100.0%	99.9%
Water			
Mft[3] in operation	10.5	10.5	10.5
Availability (%)[3]	101.8%	101.8%	101.5%

[1] Represents total installed capacity in assets owned at the end of the period, regardless of our percentage of ownership in each of the assets.

[2] Efficient natural gas production and availability were impacted by a periodic scheduled major maintenance in February 2016.

[3] Availability refers to actual availability divided by contracted availability.

Results of Operations

The table below illustrates our results of operations for the years ended December 31, 2017, 2016 and 2015.

	Year ended December 31,		
	2017	2016	2015
		$ in millions	
Revenue	$ 1,008.4	$ 971.8	$ 790.9
Other operating income	80.8	65.5	68.8
Raw materials and consumables used	(17.0)	(26.9)	(23.2)
Employee benefit expenses	(18.7)	(14.8)	(5.8)
Depreciation, amortization and impairment charges	(311.0)	(332.9)	(261.3)
Other operating expenses	(284.5)	(260.3)	(224.9)
Operating profit/(loss)	**$ 458.0**	**$ 402.4**	**$ 344.5**
Financial income	1.0	3.3	3.5
Financial expense	(463.7)	(408.0)	(333.9)
Net exchange differences	(4.1)	(9.6)	3.9
Other financial income/(expense), net	18.4	8.5	(200.2)
Financial expense, net	**$ (448.4)**	**$ (405.8)**	**$ (526.7)**
Share of profit/(loss) of associates carried under the equity method	5.3	6.7	(7.8)
Profit/(loss) before income tax	**$ 14.9**	**$ 3.4**	**$ (174.4)**
Income tax	(119.8)	(1.7)	(23.8)
Profit/(loss) for the year	**$ (104.9)**	**$ 1.6**	**$ (198.2)**
Profit/(loss) attributable to non-controlling interests	(6.9)	(6.5)	(10.8)
Loss for the year attributable to the parent company	**$ (111.8)**	**$ (4.9)**	**$ (209.0)**

Comparison of the Years Ended December 31, 2017 and 2016

The significant variances or variances of the significant components of the results of operations are discussed in the following section.

Revenues

Revenues increased by 3.8% to $1,008.4 million for the year ended December 31, 2017, compared with $971.8 million for the year ended December 31, 2016. The increase was mainly due to higher revenue per MWh produced and higher production at our solar assets in Spain. The appreciation of the euro against the U.S. dollar for the year ended December 31, 2017 compared to the year ended December 31, 2016 also contributed to the increase. This was partially offset by reduced performance of Kaxu, our solar asset in South Africa after the plant experienced technical problems. Additionally, ACT continued to deliver robust levels of production and availability. However, revenues from ACT slightly decreased due to the lower revenues in the portion of the tariff related to the operation and maintenance services, driven by lower operation and maintenance costs in 2017.

Other operating income

The following table sets forth our other operating income for the years ended December 31, 2017 and 2016:

	Year ended December 31,	
	2017	2016
Other operating income	$ in millions	
Grants	59.7	59.1
Income from various services	21.1	6.4
Total	**80.8**	**65.5**

Other operating income increased by $15.3 million to $80.8 million for the year ended December 31, 2017, compared with $65.5 million for the year ended December 31, 2016. Income from various services increased due to insurance proceeds received in Kaxu and Solana of approximately $14 million.

Income classified as grants represents the financial support provided by the U.S. Administration to Solana and Mojave consists of ITC Cash Grants and an implicit grant related to the below market interest rates of the project loans with the FFB. Grants remained stable for the years ended December 31, 2017 and 2016.

Raw materials and consumables used

Raw materials and consumables used decreased by $9.9 million to $17.0 million for the year ended December 31, 2017, compared with $26.9 million for the year ended December 31, 2016, primarily due to fewer spare parts and consumables at Solana and Mojave.

Employee benefits expenses

Employee benefit expenses increased by $4.0 million to $18.7 million for the year ended December 31, 2017, compared with $14.8 million for the year ended December 31, 2016. The increase is mainly due to the transfer of employees previously employed by subsidiaries of Abengoa who were providing services to us under the support services agreement to our subsidiaries. The transfer occurred during the first six months of 2016 and the support service agreement was terminated in the second quarter of 2016.

Depreciation, amortization and impairment charges

Depreciation, amortization and impairment charges decreased by 6.6% to $311.0 million for the year ended December 31, 2017, compared with $332.9 million for the year ended December 31, 2016. The decrease was largely attributable to $20.3 million of impairment in our wind assets that was recorded in the fourth quarter of 2016 due to lower than expected wind resource in the previous two years.

Other operating expenses

The following table sets forth our other operating expenses for the years ended December 31, 2017 and 2016:

	Year ended December 31,			
	2017		2016	
Other operating expenses	**$ in millions**	**% of revenue**	**$ in millions**	**% of revenue**
Leases and fees	6.6	0.7%	5.3	0.5%
Operation and maintenance	129.9	12.9%	133.3	13.7%
Independent professional services	36.2	3.6%	30.5	3.2%
Supplies	20.4	2.0%	17.2	1.8%
Insurance	24.3	2.4%	23.4	2.4%
Levies and duties	52.4	5.2%	44.5	4.6%
Other expenses	14.7	1.5%	6.2	0.6%
Total	**284.5**	**28.2%**	**260.3**	**26.8%**

Other operating expenses increased by 9.3% to $284.5 million for the year ended December 31, 2017, compared with $260.3 million for the year ended December 31, 2016. The increase was largely due to higher costs recorded in Other expenses as well as Levies and duties which were partially offset by lower costs recorded in Operation and maintenance. Other expenses principally increased due to provisions for legal expenses in our US assets. Levies and duties increased mainly due to $8.1 million of a one-time provision for property taxes recorded at certain plants in Spain. These cost increases were partially offset by the Operation and maintenance cost savings that resulted mainly from lower operation and maintenance expenses of ACT for the year ended December 31, 2017 compared to the year ended December 31, 2016, a year when ACT had scheduled major maintenance.

Operating profit

As a result of the above factors, operating profit increased by 13.8% to $458.0 million for the year ended December 31, 2017, compared with $402.4 million for the year ended December 31, 2016.

Financial income and financial expense

	Year ended December 31,	
Financial income and financial expense	**2017**	**2016**
	$ in millions	
Financial income	1.0	3.3
Financial expense	(463.7)	(408.0)
Net exchange differences	(4.1)	(9.6)
Other financial income/(expense), net	18.4	8.5
Financial expense, net	**(448.4)**	**(405.8)**

Financial expense

The following table sets forth our financial expense for the years ended December 31, 2017 and 2016:

Financial expense	**Year ended December 31,**	
	2017	**2016**
	$ in millions	
Expenses due to interest:		
Loans with credit entities	(253.7)	(242.9)
Other debts	(137.6)	(91.0)
Interest rates losses derivatives: cash flow hedges	(72.4)	(74.1)
Total	**(463.7)**	**(408.0)**

Financial expense increased by 13.7% to $463.7 million for the year ended December 31, 2017, compared with $408.0 million for the year ended December 31, 2016. This increase was largely attributable to the increase of expenses due to interest on Other debts, mainly due to a one-time non-monetary expense of $50.1 million resulting from the update in the estimation of Liberty's tax equity investment accounting value. Under IFRS, although the investment of Liberty is in ordinary shares, it does not qualify as equity and has been classified as a liability recorded in Grants and other liabilities, measured at amortized cost in accordance with the effective interest method.

Financial expenses related to Loans with credit entities increased mainly due the higher interest rate for the long-term Note Issuance Facility since February 2017 compared to the lower interest rate of the short-term Tranche B of the Revolving Credit Facility, which was since paid off.

Interest on other debt is primarily interest on the notes issued by ATS, ATN, ATN2, and Solaben 1/6 and the 2019 Notes.

Losses from interest rate derivatives designated as cash flow hedges correspond mainly to transfers from equity to financial expense when the hedged item is impacting the Annual Consolidated Financial Statements.

Other financial income/(expense), net

Other financial income/(expense), net	**Year ended December 31,**	
	2017	**2016**
	$ in millions	
Dividend from ACBH	10.4	28.0
Other financial income	28.8	13.0
Impairment preferred equity investment in ACBH	-	(22.1)
Other financial losses	(20.8)	(10.4)
Total	**18.4**	**8.5**

Other financial income, net increased to $18.4 million for the year ended December 31, 2017, from $8.5 million for the year ended December 31, 2016 due primarily to the gain resulting from the cancellation of the Currency Swap with Abengoa in 2017 recorded in Other financial income, as well as to the Impairment of preferred equity investment in ACBH recorded in 2016.

In accordance with the agreement reached with Abengoa with respect to the ACBH investment, Abengoa acknowledged that we are the legal owner of the dividends we retained from Abengoa. As a result, we recorded $10.4 million in our financial statements in 2017 and $28.0 million in 2016, in accordance with the accounting treatment given previously to the ACBH dividend. In addition, upon completion of Abengoa's restructuring in March 2017, we received restructured debt and equity of Abengoa. In exchange, we waived, as agreed, our rights under the ACBH agreements, including our right to further retain dividends payable to Abengoa and we wrote-off the accounting value of this instrument. The net impact of the two transactions resulted in a net loss of $5.8 million, recorded in Other financial losses. Additionally, during 2017, we sold a significant portion of the Abengoa debt and equity instruments we received and recognized a gain of $6.5 million in Other financial income. In addition, Other financial income includes a $16.2 million gain resulting from our cancelation of the Abengoa Currency Swap Agreement in 2017.

Other financial losses also include guarantees and letters of credit, wire transfers and other bank fees and other minor financial expenses.

Share of profit of associates carried under the equity method

Share of profit of associates carried under the equity method decreased to $5.3 million for the year ended December 31, 2017, compared with $6.7 million for the year ended December 31, 2016. The decrease is mainly due lower profits in Honaine.

Profit/(loss) before income tax

As a result of the previously mentioned factors, we reported a profit before income taxes of $14.9 million for the year ended December 31, 2017, compared with a profit before income taxes of $3.4 million for the year ended December 31, 2016.

Income tax

Income tax expense amounted to $119.8 million for the year ended December 31, 2017, compared with an income tax expense of $1.7 million for the year ended December 31, 2016. The increase is mainly due to the change of ownership under Section 382 of the Internal Revenue Code, which caused a one-time income tax expense of $96 million and to the U.S. Tax Reform which caused a one-time income tax expense of $19.0 million. See "Item 5.—Operating and Financial Review and Prospects—A. Operating Results—Factors Affecting the Comparability of Our Results of Operations." As a result, our effective tax rate differed from our nominal tax rate in 2017.

In 2016, our effective tax rate differs from the average nominal tax rate mainly due to a net of different effects. Permanent differences in some jurisdictions, particularly in Mexico had a positive impact in our income tax expense. This effect was offset by tax losses for which we did not record a tax credit in some jurisdictions, in accordance with IFRS.

Loss attributable to the parent company

As a result of the previously mentioned factors, loss attributable to the parent company was $111.8 million for the year ended December 31, 2017, compared with $4.9 million for the year ended December 31, 2016.

Comparison of the Years Ended December 31, 2016 and 2015

Revenues

Revenues increased by 22.9% to $971.8 million for the year ended December 31, 2016, compared with $790.9 million for the year ended December 31, 2015. The increase is largely attributable to the acquisitions of Helioenergy 1/2, Helios 1/2, Solnova 1/3/4, ATN2 in the second quarter of 2015 as well as Kaxu and Solaben 1/6 in the third quarter of 2015. Additionally, production at Mojave increased as the project entered into its second year of operations. These resulted in a net electricity production of 5,503 GWh in operation for the year ended December 31, 2016, compared with 5,001 GWh produced in operation during the year ended December 31, 2015. The impact of exchange rates was immaterial for the year ended December 31, 2016 resulting in less than a 2.7% change in revenues mostly attributable to the depreciation of the South African rand.

Other operating income

The following table sets forth our other operating income for the years ended December 31, 2016 and 2015:

	Year ended December 31,	
	2016	2015
Other operating income	$ in millions	
Grants	59.1	67.8
Income from various services	6.4	1.0
Total	**65.5**	**68.8**

Other operating income decreased by 4.8% to $65.5 million for the year ended December 31, 2016, compared with $68.8 million for the year ended December 31, 2015. The decrease was mainly due to the decrease in Grants to $59.1 million for the year ended December 31, 2016 from $67.8 million in the same period of 2015. Income classified as grants representing the financial support provided by the U.S. Administration to Solana and Mojave consists of ITC Cash Grants and an implicit grant related to the below market interest rates of the project loans with the FFB. The decrease relates to the implicit grant of Mojave and is driven by the October 2015 repayment of the short-term tranche of its loans. Income from various services for the year ended December 31, 2016 increased compared to the year ended December 31, 2015 due to the $5.1 million insurance income recorded at Solana.

Raw materials and consumables used

Raw materials and consumables used increased by $3.7 million to $26.9 million for the year ended December 31, 2016, compared with $23.2 million for the year ended December 31, 2015, primarily due to the higher amount of spare parts and consumables at Solana and raw materials of the assets acquired during 2016.

Employee benefits expenses

Employee benefit expenses increased by $9.0 million to $14.8 million for the year ended December 31, 2016, compared with $5.8 million for the year ended December 31, 2015. The increase is mainly due to the transfer of employees previously employed by subsidiaries of Abengoa who were providing services to us under the support services agreement to our subsidiaries. The transfer occurred over the first six months of 2016 and the support service agreement was terminated in the second quarter of 2016. Additionally, during 2015, Management employees of Atlantica Yield were transferred to companies within the perimeter of Atlantica Yield and the Executive Services Agreement was terminated, which has also caused an increase in employee benefits expenses.

Depreciation, amortization and impairment charges

Depreciation, amortization and impairment charges increased by 27.4% to $332.9 million for the year ended December 31, 2016, compared with $261.3 million for the year ended December 31, 2015. The increase was largely attributable to the depreciation and amortization expenses of Helios 1/2, Solnova 1/3/4 and Helioenergy 1/2 acquired in the second quarter of 2015 as well as Kaxu and Solaben 1/6 acquired in the third quarter of 2015. Additionally, in the fourth quarter of 2016, we recognized $20.3 million of impairment in our wind assets mainly due to lower than expected wind resource in the previous two years. See Note 6 to our Annual Consolidated Financial Statements.

Other operating expenses

The following table sets forth our other operating expenses for the years ended December 31, 2016 and 2015:

	Year ended December 31,			
	2016		2015	
Other operating expenses	**$ in millions**	**% of revenue**	**$ in millions**	**% of revenue**
Leases and fees	5.3	0.5%	3.9	0.5%
Operation and maintenance	133.3	13.7%	116.5	14.7%
Independent professional services	30.5	3.2%	19.0	2.4%
Supplies	17.2	1.8%	18.0	2.3%
Insurance	23.4	2.4%	20.2	2.6%
Levies and duties	44.5	4.6%	32.4	4.1%
Other expenses	6.2	0.6%	14.9	1.9%
Total	**260.3**	**26.8%**	**224.9**	**28.5%**

Other operating expenses increased by 15.8% to $260.3 million for the year ended December 31, 2016, compared with $224.9 million for the year ended December 31, 2015. This was primarily due to the other operating expenses of the companies acquired in the second and third quarter of 2015. Levies and duties correspond largely to the electricity tax of our Spanish solar assets and the increase is mainly attributable to the acquisition of Helios 1/2, Solnova 1/3/4, Helioenergy 1/2 and Solaben 1/6.

We have changed our presentation of “Other operating expenses” to better reflect the nature of our business and costs. Prior period amounts have been reclassified to conform to the new classification presented in the table above.

Operating profit

As a result of the above factors, operating profit increased by 16.8% to $402.4 million for the year ended December 31, 2016, compared with $344.5 million for the year ended December 31, 2015.

Financial income and financial expense

	Year ended December 31,	
Financial income and financial expense	**2016**	**2015**
	$ in millions	
Financial income	3.3	3.5
Financial expense	(408.0)	(333.9)
Net exchange differences	(9.6)	3.9
Other financial income/(expense), net	8.5	(200.2)
Financial expense, net	**(405.8)**	**(526.7)**

Net financial expense decreased to $405.8 million for the year ended December 31, 2016, compared with $526.7 million for the year ended December 31, 2015, mainly due to the impairment of the preferred equity investment in ACBH recognized in 2015 partially offset by the increase in the financing expense in 2016. Both effects are analyzed below.

Financial expense

The following table sets forth our financial expense for the years ended December 31, 2016 and 2015:

Financial expense	**Year ended December 31, 2016**	**2015**
Expenses due to interest:	**$ in millions**	
Loans with credit entities	(242.9)	(197.9)
Other debts	(91.0)	(81.9)
Interest rates losses derivatives: cash flow hedges	(74.1)	(54.1)
Total	**(408.0)**	**(333.9)**

Financial expense increased by 22.2% to $408.0 million for the year ended December 31, 2016, compared with $333.9 million for the year ended December 31, 2015. This increase was largely attributable to interest expenses from loans and credits of the assets acquired in the second (Helios 1/2, Solnova 1/3/4, Helioenergy 1/2 and ATN2) and third quarter (Kaxu and Solaben 1/2) of 2015. Interest expense also increased due to the interest corresponding to Tranche B of to the Revolving Credit Facility closed on June 26, 2015 and fully drawn in September 2015.

Interest on other debt is primarily interest on the notes issued by ATS, Solaben 1/6 and ATN, and the 2019 Notes, as well as interest related to the investment from Liberty in Solana. The increase is mainly due to the acquisition of Solaben 1/6 in the third quarter of 2015.

Losses from interest rate derivatives designated as cash flow hedges correspond mainly to transfers from equity to financial expense when the hedged item is impacting the Annual Consolidated Financial Statements. The increase is principally due to the acquisition of solar assets in Spain that usually hedge interest rate risk with swaps.

Other financial income/(expense), net

Other financial income/(expenses)	**Year ended December 31, 2016**	**2015**
	$ in millions	
Dividend from ACBH	28.0	18.4
Other financial income	13.0	1.5
Impairment preferred equity investment in ACBH	(22.1)	(210.4)
Other financial losses	(10.4)	(9.7)
Total	**8.5**	**(200.2)**

Other financial income, net increased to $8.5 million for the year ended December 31, 2016, compared with a $200.2 million financial expense, net for the year ended December 31, 2015.

On January 29, 2016, Abengoa informed us that several indirect subsidiaries of Abengoa in Brazil, including ACBH, initiated an insolvency procedure under Brazilian law (“reorganizaçao judiciaria”), including ACBH. According to the agreement reached with Abengoa in the third quarter of 2016, they have acknowledged that Atlantica Yield is the legal owner of the $28.0 million of dividends retained to-date from Abengoa. As a result, we recorded $28.0 million in our 2016 Annual Consolidated Financial Statements, in accordance with the accounting treatment given previously to the ACBH dividend.

Additionally, taking into account the agreement signed with Abengoa regarding the ACBH preferred equity investment, we performed a valuation of the ACBH instrument as of December 31, 2016 using a probability weighted average method. This valuation method considered the probability of the restructuring agreement being made effective and resulted in an impairment of $22.1 million. See Note 8 to the annual consolidated financial statements as of December 31, 2016 and 2015 and for the years ended December 31, 2016, 2015 and 2014 which were included in the annual report on Form 20-F filed with the SEC on March 1, 2016. This impairment is a non-cash item.

The increase in other financial income corresponds principally to $7.7 million of subordinated debt with the EPC contractor of one of our assets which has been cancelled in the third quarter of 2016 and financial income from the early payment of payables to Abengoa.

Other financial losses mainly include guarantees and letters of credit, wire transfers and other bank fees and other minor financial expenses.

Share of profit of associates carried under the equity method

Share of profit of associates carried under the equity decreased to $6.7 million for the year ended December 31, 2016, compared with a $7.8 million for the year ended December 31, 2015. The decrease is mainly due to the results of Helioenergy 1/2 which were recorded under the equity method from the acquisition of the initial 29.6% stake in February 2015 until May 2015 when we gained control of Helioenergy 1/2 and fully consolidated the asset.

Profit/(loss) before income tax

As a result of the above factors, we reported a profit amounting to $3.4 million for the year ended December 31, 2016, compared with a loss before income taxes of $174.4 million for the year ended December 31, 2015.

Income tax

Income tax expense amounted to $1.7 million for the year ended December 31, 2016, compared with an income tax expense of $23.8 million for the year ended December 31, 2015. In 2016, our effective tax rate differs from the average nominal tax rate mainly due to a net of different effects. Permanent differences in some jurisdictions, particularly in Mexico had a positive impact in our income tax expense. This effect was offset by tax losses for which we did not record a tax credit in some jurisdictions, in accordance with IFRS.

Income tax expense amounted to $23.8 million for the year ended December 31, 2015. Our effective tax rate differed from the average nominal tax rate mainly due to permanent differences resulting primarily from inflationary effects in ACT and incentives related mainly to the tax exemption of ACBH dividends.

Profit attributable to non-controlling interest

Profit attributable to non-controlling interest decreased by 39.7% to $6.5 million for the year ended December 31, 2016, compared with $10.8 million for the year ended December 31, 2015 mainly due to lower results in most of the projects in which we have partners.

Loss attributable to the parent company

As a result of the above factors, loss attributable to the parent company decreased to $4.9 million for the year ended December 31, 2016, compared with a loss attributable to the parent company of $209.0 million for the year ended December 31, 2015.

Segment Reporting

As of December 31, 2017, we organize our business into the following three geographies where the contracted assets and concessions are located:

- North America;
- South America; and
- EMEA.

In addition, we have identified the following business sectors based on the type of activity:

- Renewable Energy, which includes our activities related to the production electricity from solar power and wind plants;
- Efficient Natural Gas (previously named “conventional”) Power, which includes our activities related to the production of electricity and steam from natural gas;
- Electric Transmission, which includes our activities related to the operation of electric transmission lines; and
- Water, which includes our activities related to desalination plants.

As a result, we report our results through the year ended December 31, 2017 in accordance with both criteria.

Comparison of the Years Ended December 31, 2017 and 2016

Revenue and Further Adjusted EBITDA by geography

The following table sets forth our revenue, Further Adjusted EBITDA and volumes for the years ended December 31, 2017 and 2016, by geographic region:

Revenue by geography

	Year ended December 31,			
	2017		2016	
Revenue by geography	**$ in millions**	**% of revenue**	**$ in millions**	**% of revenue**
North America	332.7	33.0%	337.0	34.7%
South America	120.8	12.0%	118.8	12.2%
EMEA	554.9	55.0%	516.0	53.1%
Total revenue	**1,008.4**	**100.0%**	**971.8**	**100.0%**

Further Adjusted EBITDA by geography

	Year ended December 31,			
	2017		2016	
Further Adjusted EBITDA by geography	**$ in millions**	**% of revenue**	**$ in millions**	**% of revenue**
North America	282.3	84.9%	284.7	84.5%
South America	108.8	90.0%	124.6	104.9%
EMEA	388.2	70.0%	354.0	68.6%
Further Adjusted EBITDA(1)	**779.3**	**77.3%**	**763.3**	**78.5%**

Note:—

(1) Further Adjusted EBITDA is calculated as profit/(loss) for the year attributable to the parent company, after adding back loss/(profit) attributable to non-controlling interest from continued operations, income tax, share of profit/(loss) of associates carried under the equity method, finance expense net, depreciation, amortization and impairment charges of entities included in the Annual Consolidated Financial Statements, and dividends received from our preferred equity investment in ACBH. Further Adjusted EBITDA for the year ended December 31, 2016 and for the first quarter of 2017 includes compensation received from Abengoa in lieu of ACBH dividends. Further Adjusted EBITDA is not a measure of performance under IFRS as issued by the IASB, and you should not consider Further Adjusted EBITDA as an alternative to operating income or profits or as a measure of our operating performance, cash flows from operating, investing and financing activities or as a measure of our ability to meet our cash needs or any other measures of performance under generally accepted accounting principles. We believe that Further Adjusted EBITDA is a useful indicator of our ability to incur and service our indebtedness and can assist securities analysts, investors and other parties to evaluate us. Further Adjusted EBITDA and similar measures are used by different companies for different purposes and are often calculated in ways that reflect the circumstances of those companies. Further Adjusted EBITDA may not be indicative of our historical operating results, nor is it meant to be predictive of potential future results. See "Presentation of Financial Information —Non-GAAP Financial Measures."

Volume by geography

	Volume produced/availability	
	Year ended December 31,	
Volume by geography	**2017**	**2016**
North America (GWh)	3,695	3,684
South America (miles in operation)	1,099	1,099
South America (GWh)	325	296
EMEA (GWh)	1,519	1,523
EMEA (capacity in M ft^3 per day)	10.5	10.5

North America

Revenues decreased slightly by 1.3% to $332.7 million for the year ended December 31, 2017 compared with $337.0 million for the year ended December 31, 2016. The decrease was primarily due to lower revenues at ACT. Although ACT continued to deliver robust levels of production and availability, revenues in ACT decreased due to lower revenues in the portion of the tariff related to the operation and maintenance services, driven by lower operation and maintenance costs for the year ended December 31, 2017. Further Adjusted EBITDA margin remained stable around 85% for the year 2017 compared to 2016.

South America

Revenues increased slightly by 1.7% to $120.8 million for the year ended December 31, 2017, compared with $118.8 million for the year ended December 31, 2016 mainly due to higher production in our wind assets in Uruguay. Further Adjusted EBITDA decreased to $108.8 million for the year ended December 31, 2017, compared with $124.6 million for the year ended December 31, 2016. According to the agreement reached with Abengoa in the third quarter of 2016, Abengoa acknowledged that we are the legal owner of the dividends retained from Abengoa. As a result, we recorded $28.0 million for the year ended December 31, 2016 and $10.4 million for the year ended December 31, 2017 in accordance with the accounting treatment given previously to the ACBH dividend. Further Adjusted EBITDA margin decreased to 90.0% for the year ended December 31, 2017 from 104.9% for the year ended December 31, 2016 also due to the accounting treatment previously given to the ACBH dividend.

EMEA

Revenues increased by 7.5% to $554.9 million for the year ended December 31, 2017, compared with $516.0 million for the year ended December 31, 2016. The increase was mainly due to higher revenue per MWh produced and higher production of our solar assets in Spain, driven by higher solar radiation levels. The appreciation of the euro against the U.S. dollar for the year ended December 31, 2017 compared to the year ended December 31, 2016 also contributed part of the increase. This was partially offset by reduced performance of Kaxu, our solar asset in South Africa after the plant experienced technical problems. The repairs were completed in the fourth quarter of 2017 and insurance payments claimed for repairs of water pumps were collected in the second quarter of 2017. As a result, Further Adjusted EBITDA increased to $388.2 million for the year ended December 31, 2017, compared with $354.0 million for the year ended December 31, 2016.

Revenue and Further Adjusted EBITDA by business sector

The following table sets forth our revenue, Further Adjusted EBITDA and volumes for the years ended December 31, 2017 and 2016, by business sector:

Revenue by business sector

Revenue by business sector	Year ended December 31, 2017 $ in millions	2017 % of revenue	2016 $ in millions	2016 % of revenue
Renewable energy	767.2	76.1%	724.3	74.5%
Efficient natural gas power	119.8	12.0%	128.1	13.2%
Electric transmission lines	95.1	9.4%	95.1	9.8%
Water	26.3	2.6%	24.3	2.5%
Total revenue	**1,008.4**	**100.0%**	**971.8**	**100.0%**

Further Adjusted EBITDA by business sector

Further Adjusted EBITDA by business sector	Year ended December 31, 2017 $ in millions	2017 % of revenue	2016 $ in millions	2016 % of revenue
Renewable energy	569.2	74.2%	538.4	74.3%
Efficient natural gas power	106.1	88.6%	106.5	83.2%
Electric transmission lines	87.7	92.2%	104.8	110.2%
Water	16.3	62.0%	13.6	56.0%
Further Adjusted EBITDA[1]	**779.3**	**77.3%**	**763.3**	**78.5%**

Note:—

(1) Further Adjusted EBITDA is calculated as profit/(loss) for the year attributable to the parent company, after adding back loss/(profit) attributable to non-controlling interest from continued operations, income tax, share of profit/(loss) of associates carried under the equity method, finance expense net, depreciation, amortization and impairment charges of entities included in the Annual Consolidated Financial Statements, and dividends received from our preferred equity investment in ACBH. Further Adjusted EBITDA for the year ended December 31, 2016 and for the first quarter of 2017 includes compensation received from Abengoa in lieu of ACBH dividends. Further Adjusted EBITDA is not a measure of performance under IFRS as issued by the IASB, and you should not consider Further Adjusted EBITDA as an alternative to operating income or profits or as a measure of our operating performance, cash flows from operating, investing and financing activities or as a measure of our ability to meet our cash needs or any other measures of performance under generally accepted accounting principles. We believe that Further Adjusted EBITDA is a useful indicator of our ability to incur and service our indebtedness and can assist securities analysts, investors and other parties to evaluate us. Further Adjusted EBITDA and similar measures are used by different companies for different purposes and are often calculated in ways that reflect the circumstances of those companies. Further Adjusted EBITDA may not be indicative of our historical operating results, nor is it meant to be predictive of potential future results. See “Presentation of Financial Information—Non-GAAP Financial Measures.”

Volume by business sector

Volume by business sector	Volume produced/availability Year ended December 31, 2017	2016
Renewable energy (GWh)	3,167	3,087
Efficient natural gas power (GWh)	2,372	2,416
Electric transmission lines (miles in operation)	1,099	1,099

Renewable energy

Revenue increased by 5.9% to $767.2 million for the year ended December 31, 2017, compared with $724.3 million for the year ended December 31, 2016. The increase was mainly due to higher revenue per MWh produced and higher production of our solar assets in Spain. The appreciation of the euro against the U.S. dollar for the year ended December 31, 2017 compared to the year ended December 31, 2016 also contributed part of the increase. As a result of this effect and of the good performance of our Spanish solar assets, Further Adjusted EBITDA increased to $569.2 million for the year ended December 31, 2017, which represented an increase of $30.8 million with respect to the year ended December 31, 2016. Further Adjusted EBITDA margin remained stable for the years ended December 31, 2017 and 2016.

Efficient natural gas power

Revenue decreased by 6.5% to $119.8 million for the year ended December 31, 2017, compared with $128.1 million for the year ended December 31, 2016 ACT continued to deliver robust levels of production and availability, however revenues decreased due to the lower revenues in the portion of the tariff related to the operation and maintenance services, driven by lower operation and maintenance costs for the year ended December 31, 2016. Operation and maintenance costs were lower for the year ended December 31, 2017, since operation and maintenance costs are typically higher in the months prior to a major maintenance, which took place in the first quarter of 2016. As a result, Further Adjusted EBITDA margin increased to 88.6% for the year ended December 31, 2017, from 83.2% for the year ended December 31, 2016.

Electric transmission lines

Revenue remained stable at $95.1 million for the year ended December 31, 2017 and 2016. Further Adjusted EBITDA decreased by 16.3% mainly due to difference in the amount of the ACBH dividend recognized in for the year ended December 31, 2016 as compared to the year ended December 31, 2017. In the agreement reached with Abengoa in the third quarter of 2016, Abengoa acknowledged that we are the legal owner of the dividends retained from Abengoa prior to Abengoa's restructuring. As a result, we recorded $28.0 million for the year ended December 31, 2016 and $10.4 million for the year ended December 31, 2017, in accordance with the accounting treatment given previously to the ACBH dividend.

Water

Revenue amounted to $26.3 million for the year ended December 31, 2017 and Further Adjusted EBITDA amounted to $16.3 million for the year ended December 31, 2017, resulting in 56% Adjusted EBITDA margin.

Comparison of the Years Ended December 31, 2016 and 2015

Revenue and Further Adjusted EBITDA by geography

The following table sets forth our revenue, Further Adjusted EBITDA and volumes for the years ended December 31, 2016 and 2015, by geographic region:

Revenue by geography

Revenue by geography	2016 $ in millions	2016 % of revenue	2015 $ in millions	2015 % of revenue
	Year ended December 31,			
North America	337.0	34.7%	328.1	41.5%
South America	118.8	12.2%	112.5	14.2%
EMEA	516.0	53.1%	350.3	44.3%
Total revenue	**971.8**	**100.0%**	**790.9**	**100.0%**

Further Adjusted EBITDA by geography

Further Adjusted EBITDA by geography	2016 $ in millions	2016 % of revenue	2015 $ in millions	2015 % of revenue
	Year ended December 31,			
North America	284.7	84.5%	279.6	85.2%
South America	124.6	104.9%	110.9	98.6%
EMEA	354.0	68.6%	233.7	66.7%
Further Adjusted EBITDA(1)	**763.3**	**78.5%**	**624.2**	**78.9%**

Note:—

(1) Further Adjusted EBITDA is calculated as profit/(loss) for the year attributable to the parent company, after adding back loss/(profit) attributable to non-controlling interest from continued operations, income tax, share of profit/(loss) of associates carried under the equity method, finance expense net, depreciation, amortization and impairment charges of entities included in the Annual Consolidated Financial Statements, and dividends received from our preferred equity investment in ACBH. Further Adjusted EBITDA for 2016 includes compensation received from Abengoa in lieu of ACBH dividends. Further Adjusted EBITDA is not a measure of performance under IFRS as issued by the IASB, and you should not consider Further Adjusted EBITDA as an alternative to operating income or profits or as a measure of our operating performance, cash flows from operating, investing and financing activities or as a measure of our ability to meet our cash needs or any other measures of performance under generally accepted accounting principles. We believe that Further Adjusted EBITDA is a useful indicator of our ability to incur and service our indebtedness and can assist securities analysts, investors and other parties to evaluate us. Further Adjusted EBITDA and similar measures are used by different companies for different purposes and are often calculated in ways that reflect the circumstances of those companies. Further Adjusted EBITDA may not be indicative of our historical operating results, nor is it meant to be predictive of potential future results. See “Presentation of Financial Information—Non-GAAP Financial Measures.”

Volume by geography

Volume by geography	Volume produced/availability Year ended December 31, 2016	2015
North America (GWh)	3,684	3,687
South America (miles in operation)	1,099	1,099
South America (GWh)	296	313
EMEA (GWh)	1,523	1,001
EMEA (capacity in M ft^3 per day)	10.5	10.5

North America

Revenues increased by 2.7% to $337.0 million for the year ended December 31, 2016, compared with $328.1 million for the year ended December 31, 2015. The increase was primarily due to higher production at Mojave, one of our assets in the US which is in its second year of operations and performing better than its initial year. As a result, Further Adjusted EBITDA increased to $284.7 million for the year ended December 31, 2016, compared with $279.6 million for the year ended December 31, 2015. Further Adjusted EBITDA margin remained stable.

South America

Revenues increased by 5.6% to $118.8 million for the year ended December 31, 2016, compared with $112.5 million for the year ended December 31, 2015. The increase was mainly attributable to the revenues generated by ATN2 which was acquired in the second quarter of 2015. Further Adjusted EBITDA increased to $124.6 million for the year ended December 31, 2016, compared with $110.9 million for the year ended December 31, 2015. According to the agreement reached with Abengoa in the third quarter of 2016, they have acknowledged that Atlantica Yield is the legal owner of the $28.0 million dividends that had been retained to Abengoa. As a result, we have recorded $28.0 million in our financial statements in accordance with the accounting treatment given previously to the ACBH dividend.

EMEA

Revenues increased by 47.3% to $516.0 million for the year ended December 31, 2016, compared with $350.3 million for the year ended December 31, 2015. The increase was mostly driven by the acquisitions of Helios ½, Solnova 1/3/4 and Helioenergy ½ in the second quarter of 2015 as well as Solaben 1/6 and Kaxu in the third quarter of 2015. As a result, Further Adjusted EBITDA increased to $354.0 million for the year ended December 31, 2016, compared with $233.7 million for the year ended December 31, 2015. Further Adjusted EBITDA margin remained stable as margins of the projects acquired in 2015 are similar to margins of the projects we owned last year.

Revenue and Further Adjusted EBITDA by business sector

The following table sets forth our revenue, Further Adjusted EBITDA and volumes for the years ended December 31, 2016 and 2015, by business sector:

Revenue by business sector

Revenue by business sector	Year ended December 31, 2016 $ in millions	2016 % of revenue	2015 $ in millions	2015 % of revenue
Renewable energy	724.3	74.5%	543.0	68.7%
Efficient natural gas power	128.1	13.2%	138.7	17.5%
Electric transmission lines	95.1	9.8%	86.4	10.9%
Water	24.3	2.5%	22.8	2.9%
Total revenue	**971.8**	**100.0%**	**790.9**	**100.0%**

Further Adjusted EBITDA by business sector

Further Adjusted EBITDA by business sector	Year ended December 31, 2016 $ in millions	2016 % of revenue	2015 $ in millions	2015 % of revenue
Renewable energy	538.4	74.3%	414.0	76.2%
Efficient natural gas power	106.5	83.2%	107.7	77.6%
Electric transmission lines	104.8	110.2%	89.0	103.1%
Water	13.6	56.0%	13.5	59.6%
Further Adjusted EBITDA(1)	**763.3**	**78.5%**	**624.2**	**78.9%**

Note:—

(1) Further Adjusted EBITDA is calculated as profit/(loss) for the year attributable to the parent company, after adding back loss/(profit) attributable to non-controlling interest from continued operations, income tax, share of profit/(loss) of associates carried under the equity method, finance expense net, depreciation, amortization and impairment charges of entities included in the Annual Consolidated Financial Statements, and dividends received from our preferred equity investment in ACBH. Further Adjusted EBITDA for the year ended December 31, 2016 includes compensation received from Abengoa in lieu of ACBH dividends. Further Adjusted EBITDA is not a measure of performance under IFRS as issued by the IASB, and you should not consider Further Adjusted EBITDA as an alternative to operating income or profits or as a measure of our operating performance, cash flows from operating, investing and financing activities or as a measure of our ability to meet our cash needs or any other measures of performance under generally accepted accounting principles. We believe that Further Adjusted EBITDA is a useful indicator of our ability to incur and service our indebtedness and can assist securities analysts, investors and other parties to evaluate us. Further Adjusted EBITDA and similar measures are used by different companies for different purposes and are often calculated in ways that reflect the circumstances of those companies. Further Adjusted EBITDA may not be indicative of our historical operating results, nor is it meant to be predictive of potential future results. See “Presentation of Financial Information—Non-GAAP Financial Measures.”

Volume by business sector

Volume by business sector	Volume produced/availability Year ended December 31, 2016	2015
Renewable energy (GWh)	3,087	2,536
Efficient natural gas power (GWh)	2,416	2,465
Electric transmission lines (miles in operation)	1,099	1,099

Renewable energy

Revenue increased by 33.4% to $724.3 million for the year ended December 31, 2016, compared with $543.0 million for the year ended December 31, 2015. The increase was mainly attributable to the acquisitions of Helios ½, Solnova 1/3/4 and Helioenergy ½ in the second quarter of 2015 as well as Solaben 1/6 and Kaxu in the third quarter of 2015. Additionally, Mojave, one of our solar asset in the U.S. entered into its second year of operations and increased its production for the year ended December 31, 2016. As a consequence, our net electricity production reached 3,087 GWh for the year ended December 31, 2016, compared with 2,536 GWh produced during the year ended December 31, 2015. Further Adjusted EBITDA amounted to $538.4 million for the year ended December 31, 2016, which represented an increase of $124.4 million with respect to the year ended December 31, 2015, mainly due to the effect of the projects acquired during the second and third quarters of 2015. Further Adjusted EBITDA margin has decreased principally as a result of the higher allocation of the general and administrative expenses to the segment. Additionally, the Further Adjusted EBITDA decreased due to the reduction of the other operating income of Mojave driven by a lower amount of implicit grant which represents a non-monetary benefit of the below market interest rates of the project loan with the FFB. Mojave paid off its short-term tranche of the loan in October 2015.

Efficient natural gas power (previously named "conventional")

Revenue decreased by 7.6% to $128.1 million for the year ended December 31, 2016, compared with $138.7 million for the year ended December 31, 2015 due to the lower revenues in the portion of the tariff related to the operation and maintenance services, driven by lower operation and maintenance costs in the year ended December 31, 2016. As a result, Further Adjusted EBITDA margin increased to 83.2% for the year ended December 31, 2016, from 77.6% for the year ended December 31, 2015.

Electric transmission lines

Revenue increased by 10.1% to $95.1 million for the year ended December 31, 2016, compared with $86.4 million for the year ended December 31, 2015. The increase was mostly attributable to the acquisition of ATN2 during the second quarter of 2015. All assets operated with very high levels of availability during 2016. Further Adjusted EBITDA margin increased from 103.1% for the year ended December 31, 2015 to 110.2% for the year ended December 31, 2016 primarily due to the ACBH dividend recorded in the third quarter of 2016. In the agreement reached with Abengoa in the third quarter of 2016, Abengoa acknowledged that Atlantica Yield is the legal owner of the $28.0 million dividends that had been retained from Abengoa. As a result, we have recorded $28.0 million in our Annual Consolidated Financial Statements, in accordance with the accounting treatment given previously to the ACBH dividend. The comparable period of the last year includes $18.4 million representing three quarters worth of dividend under the ACBH preferred equity investment.

Water

Revenue amounted to $24.3 million for the year ended December 31, 2016, compared to $22.8 million for the year ended December 31, 2015 due to the acquisition of Skikda in February 2015. The asset contributed eleven months to our revenue in the prior year compared to the full twelve months of revenue in 2016. Further Adjusted EBITDA amounted to $13.6 million for the year ended 2016, compared to $13.5 million for the year ended December 31, 2015. The decrease of the Adjusted EBITDA margin from 59.6% for the year ended December 31, 2015 to 56.0% for the year ended December 31, 2016, was mainly driven by the higher allocation of general and administrative expenses to the segment in 2016.

B. Liquidity and Capital Resources

The liquidity and capital resources discussion which follows contains certain estimates as of the date of this annual report of our sources and uses of liquidity (including estimated future capital resources and capital expenditures) and future financial and operating results. These estimates, while presented with numerical specificity, necessarily reflect numerous estimates and assumptions made by us with respect to industry performance, general business, economic, regulatory, market and financial conditions and other future events, as well as matters specific to our businesses, all of which are difficult or impossible to predict and many of which are beyond our control. These estimates reflect subjective judgment in many respects and thus are susceptible to multiple interpretations and periodic revisions based on actual experience and business, economic, regulatory, financial and other developments. As such, these estimates constitute forward-looking information and are subject to risks and uncertainties that could cause our actual sources and uses of liquidity (including estimated future capital resources and capital expenditures) and financial and operating results to differ materially from the estimates made here, including, but not limited to, our performance, industry performance, general business and economic conditions, customer requirements, competition, adverse changes in applicable laws, regulations or rules, and the various risks set forth in this annual report. See “Cautionary Statements Regarding Forward-Looking Statements.”

In addition, these estimates reflect assumptions of our management as of the time that they were prepared as to certain business decisions that were and are subject to change. These estimates also may be affected by our ability to achieve strategic goals, objectives and targets over the applicable periods. The estimates cannot, therefore, be considered a guarantee of future sources and uses of liquidity (including estimated future capital resources and capital expenditures) and future financial and operating results, and the information should not be relied on as such. None of us, or our board of directors, advisors, officers, directors or representatives intends to, and each of them disclaims any obligation to, update, revise, or correct these estimates, except as otherwise required by law, including if the estimates are or become inaccurate (even in the short-term).

The inclusion in this annual report of these estimates should not be deemed an admission or representation by us or our board of directors that such information is viewed by us or our board of directors as material information of ours. Such information should be evaluated, if at all, in conjunction with the historical financial statements and other information about us contained in this annual report. None of us, or our board of directors, advisors, officers, directors or representatives has made or makes any representation to any prospective investor or other person regarding our ultimate performance compared to the information contained in these estimates or that forecasted results will be achieved. In light of the foregoing factors and the uncertainties inherent in the information provided above, investors are cautioned not to place undue reliance on these estimates. Our liquidity plans are subject to a number of risks and uncertainties, some of which are outside of our control. Macroeconomic conditions could limit our ability to successfully execute our business plans and, therefore, adversely affect our liquidity plans. See “Item 3.D—Risk Factors.”

Our principal liquidity and capital requirements consist of the following:

- debt service requirements on our existing and future debt;
- cash dividends to investors; and
- acquisitions of new companies and operations. See “Item 4.B—Business Overview—Our Growth Strategy.”

As a normal part of our business, depending on market conditions, we will from time to time consider opportunities to repay, redeem, repurchase or refinance our indebtedness. Changes in our operating plans, lower than anticipated sales, increased expenses, acquisitions or other events may cause us to seek additional debt or equity financing in future periods. There can be no guarantee that financing will be available on acceptable terms or at all. Debt financing, if available, could impose additional cash payment obligations and additional covenants and operating restrictions. In addition, any of the items discussed in detail under “Item 3.D—Risk Factors” in this annual report and other factors may also significantly impact our liquidity.

Liquidity position

As of December 31, 2017, our cash and cash equivalents at the project company level were $520.9 million as compared with $472.6 million as of December 31, 2016. In addition, our cash and cash equivalents at the Atlantica Yield plc level were $148.5 million as of December 31, 2017, compared with $122.2 million as of December 31, 2016. Additionally, as of December 31, 2017, we had $71 million available under our Revolving Credit Facility (nil as of December 31, 2016) which made out total corporate liquidity amount to $219.5 million.

Sources of liquidity

We expect our ongoing sources of liquidity to include cash on hand, cash generated from our operations, project debt arrangements, corporate debt and the issuance of additional equity securities, as appropriate, given market conditions. Our financing agreements consist mainly of the project-level financings for our various assets, the 2019 Notes, the Revolving Credit Facility, the Note Issuance Facility and a line of credit with a local bank.

On November 17, 2014, we issued the 2019 Notes in an aggregate principal amount of $255 million. The 2019 Notes accrue annual interest of 7.000% payable semi-annually beginning on May 15, 2015 until their maturity date of November 15, 2019. As required by the Indenture governing the 2019 Notes, we have obtained a public credit rating for the 2019 Notes from S&P and Moody’s. See “Item 5.B—Liquidity and Capital Resources—Financing Arrangements—2019 Notes.”

On December 3, 2014, we entered into the Revolving Credit Facility in the total amount of up to $125 million. On December 22, 2014, we drew down $125 million under the Revolving Credit Facility, which we refer to as Tranche A. Loans under Tranche A of the Revolving Credit Facility accrue interest at a rate per annum equal to: (A) for Eurodollar rate loans, LIBOR plus 2.75% and (B) for base rate loans, the highest of (i) the rate per annum equal to the weighted average of the rates on overnight U.S. Federal funds transactions with members of the U.S. Federal Reserve System arranged by U.S. Federal funds brokers on such day plus ½ of 1.00%, (ii) the U.S. prime rate and (iii) LIBOR plus 1.00%, in any case, plus 1.75%. We hedged the principal outstanding under the Tranche A of the Revolving Credit Facility with a swap that fixed the interest rate at 4.7%. Loans under Tranche A of the Revolving Credit Facility mature on December 22, 2018. Loans prepaid by us under Tranche A of the Revolving Credit Facility may be re-borrowed until their maturity date of December 22, 2018. In 2017, we prepaid partially the principal outstanding under the Tranche A of the Revolving Credit Facility, leaving a balance of $54 million outstanding and $71 million of the Revolving Credit Facility available as of December 31, 2017. See "Item 5.B—Liquidity and Capital Resources—Financing Arrangements— Revolving Credit Facility."

On May 14, 2015, we closed a private placement of our shares that resulted in the issuance of 20,217,260 new shares with total net proceeds of $664 million.

On June 26, 2015, we amended and restated our Revolving Credit Facility for a new Tranche B, with a total size of $290 million. Tranche B was initially set to mature in December 2017 but was prepaid and canceled in March 2017 with the proceeds of the Note Issuance Facility we entered into in February 2017.

The proceeds of the Revolving Credit Facility and the proceeds of the capital increase were used to finance the acquisitions discussed above. See "Item 4.B—Business Overview."

On February 10, 2017, we signed a Note Issuance Facility, a senior secured note facility with a group of funds managed by Westbourne Capital as purchasers of the notes issued thereunder for a total amount of €275 million (approximately $330 million), with three series of notes. Series 1 notes worth €92 million mature in 2022; series 2 notes worth €91.5 million mature in 2023; and series 3 notes worth €91.5 million mature in 2024. Interest on all three series accrues at a rate per annum equal to the sum of 3-month EURIBOR plus 4.90%. The proceeds of the Note Issuance Facility were used to repay and subsequently cancel the Tranche B under our Revolving Credit Facility. We fully hedged the Note Issuance Facility with a swap that fixed the interest rate at 5.5%.

In July 2017, we signed a line of credit with a local bank for up to €10.0 million (approximately $12.0 million) which is available in euros or U.S. dollars. Amounts drawn accrue interest at a rate per annum equal to EURIBOR plus 2.25% or LIBOR plus 2.25%, depending on the currency. The credit facility has a maturity date of July 20, 2018. The line was fully drawn in 2017 and was used to prepay a part of Tranche A of the Revolving Credit Facility.

Our ability to meet our debt service obligations and other capital requirements, including capital expenditures, as well as acquisitions, will depend on our future operating performance which, in turn, will be subject to general economic, financial, business, competitive, legislative, regulatory and other conditions, many of which are beyond our control.

We believe that our existing liquidity position and cash flows from operations will be sufficient to meet our requirements and commitments for the next 12 months, to distribute dividends to our investors and to finance growth. Based on our current level of operations, we believe our cash flow from operations, available cash and available borrowings under our financing agreements will be adequate to meet our future liquidity needs for at least the next twelve months. Please see "Item 3.D—Risk Factors—Risks Related to Our Indebtedness—Potential future defaults by our subsidiaries, Abengoa or other persons could adversely affect us."

Debt service

Principal payments on debt as of December 31, 2017, are due in the following periods according to their contracted maturities:

Repayment schedule by geography

Repayment schedule by geography	Total	Up to one year	Between one and three years	Between three and five years	Subsequent years
			$ in millions		
North America	$ 1,821.1	$ 63.9	$ 149.2	$ 171.3	$ 1,436.7
South America	876.0	32.8	54.4	64.7	724.1
EMEA	2,778.1	149.6	307.8	357.9	1,962.8
Total project debt	**$ 5,475.2**	**$ 246.3**	**$ 511.4**	**$ 593.9**	**$ 4,123.6**
Corporate debt	**$ 643.1**	**$ 68.9**	**$ 253.4**	**$ 107.3**	**$ 213.5**
Total	**$ 6,118.3**	**$ 315.2**	**$ 764.8**	**$ 701.2**	**$ 4,337.1**

Repayment schedule by business sector	Total	Up to one year	Between one and three years	Between three and five years	Subsequent years
			$ in millions		
Renewable energy	$ 4,162.6	$ 199.4	$ 408.2	$ 467.3	$ 3,087.6
Efficient natural gas power	579.2	18.4	53.4	68.3	439.1
Electric transmission	698.3	23.5	39.6	47.2	588.0
Water	35.1	5.0	10.2	11.1	8.9
Total project debt	**$ 5,475.2**	**$ 246.3**	**$ 511.4**	**$ 593.9**	**$ 4,123.6**
Corporate debt	**$ 643.1**	**$ 68.9**	**$ 253.4**	**$ 107.3**	**$ 213.5**
Total	**$ 6,118.3**	**$ 315.2**	**$ 764.8**	**$ 701.2**	**$ 4,337.1**

The debt maturities relate to project debt that will be repaid with cash flows generated from the projects in respect of which that financing was incurred.

Cash dividends to investors

We intend to distribute to holders of our shares a significant portion of our cash available for distribution less all cash expense including corporate debt service and corporate general and administrative expenses and less reserves for the prudent conduct of our business (including, among other things, dividend shortfall as a result of fluctuations in our cash flows). Our target payout ratio is 80% of our cash available for distribution, on an annual basis. We intend to distribute a quarterly dividend to shareholders. Our board of directors may, by resolution, amend the cash dividend policy at any time. The determination of the amount of the cash dividends to be paid to holders of our shares will be made by our board of directors and will depend upon our financial condition, results of operations, cash flow, long-term prospects and any other matters that our board of directors deem relevant.

The cash available for distribution is likely to fluctuate from quarter to quarter, and in some cases significantly, mainly as a result of the seasonality of our assets and the terms of our financing arrangements among other factors. Accordingly, during quarters in which our projects generate cash available for distribution in excess of the amount necessary for us to pay our stated quarterly dividend, we may reserve a portion of the excess to fund cash distributions in future quarters. In quarters in which we do not generate sufficient cash available for distribution to fund our stated quarterly cash dividend, if our board of directors so determines, we may use retained cash flow from other quarters, as well as other sources of cash to pay dividend to our shareholders.

We declared our first quarterly dividend in November 2014 and paid it on December 15, 2014. Since then, we declared and paid quarterly dividends in 2014 and 2015. On November 5, 2015, our board of directors approved a quarterly dividend corresponding to the third quarter of 2015. The dividend was paid on December 16, 2015, to shareholders of record as of November 30, 2015, and from that amount we retained $9 million of the dividend attributable to Abengoa in accordance with the provisions of the parent support agreement. See "Item 4.B—Business Overview—Electric Transmission—Exchangeable Preferred Equity Investment in Abengoa Concessões Brasil Holding."

In February 2016, taking into consideration the uncertainties resulting from the situation of Abengoa, the board of directors decided to postpone the decision whether to declare a dividend in respect of the fourth quarter of 2015 until the second quarter of 2016. In May 2016, considering the uncertainties that remained in Abengoa's situation, our board of directors decided not to declare a dividend in respect of the fourth quarter of 2015 and to postpone the decision on whether to declare a dividend in respect of the first quarter 2016 until we had obtained greater clarity on cross default and change of ownership issues. On August 3, 2016, the board of directors decided to declare a dividend of $0.145 per share for the first quarter of 2016 and a dividend of $0.145 per share for the second quarter of 2016. The dividend was paid on September 15, 2016, to shareholders of record August 31, 2016. From that amount, we retained $12.3 million of the dividend attributable to Abengoa. On November 11, 2016, our board of directors, based on waivers or forbearances obtained to that date, decided to declare a dividend of $0.163 per share, which was paid on December 15, 2016, to shareholders of record on November 30, 2016. From that amount, we retained $6.7 million of the dividend attributable to Abengoa.

On February 27, 2017, the board of directors declared a dividend of $0.25 per share corresponding to the fourth quarter of 2016, which was paid on March 15, 2017. From that amount, we retained $10.4 million of the dividend attributable to Abengoa. On May 12, 2017, the board of directors declared a dividend of $0.25 per share corresponding to the first quarter of 2017, which was paid on June 15, 2017. On July 28, 2017, the board of directors declared a dividend of $0.26 per share corresponding to the second quarter of 2017, which was paid on September 15, 2017. On November 13, 2017, our board of directors approved a dividend of $0.29 per share, which was paid on December 15, 2017. On February 27, 2018, our board of directors declared a dividend of $0.31 per share which is expected to be paid on or about March 22, 2018.

Acquisitions

On February 3, 2015, we completed the acquisition of a 25.5% stake in Honaine and a 34.2% stake in Skikda. On February 23, 2015, we completed the acquisition of a 29.6% stake in Helioenergy 1/2. The total purchase price paid for these assets amounted to $94 million and was financed with a portion of the proceeds of the Revolving Credit Facility.

On May 13, 2015 and May 14, 2015, we completed the acquisition of Helios 1/2 and Solnova 1/3/4. On May 25, 2015, we completed the acquisition of the remaining 70.4% stake in Helioenergy 1/2. On July 30, 2015, we completed the acquisition of a 51% stake in Kaxu. The total purchase price paid for these assets amounted to $682 million and was financed with the proceeds of a capital increase completed in May 2015.

On June 25, 2015, we completed the acquisition of ATN2 from Abengoa and Sigma, a third-party financial investor in ATN2. On September 30, 2015, we completed the acquisition of Solaben 1/6. In addition, on January 7, 2016, we completed the acquisition from JGC of a 13% in Solacor 1/2, a 100 MW solar complex in Spain where we already owned a 74% stake. The total purchase price for these assets amounted to $378 million and was mainly financed with Tranche B of our Credit Facility.

On August 3, 2016, we completed the acquisition of an 80.0% stake in Seville PV, a 1MW PV plant located next to Solnova 1/3/4 for a total consideration of $3.2 million, that we financed with cash on hand.

On February 28, 2017, we completed the acquisition of a 12.5% interest in a 114-mile transmission line in the U.S. from Abengoa at cost. We expect our total investment to be up to $10 million in the coming three years, including the initial amount invested at cost. We expect to finance the acquisition with cash on hand.

On February 28, 2018, we completed the acquisition of a 4 MW mini-hydroelectric power plant in Peru for $9 million. The plant reached COD in 2012. It has a fixed-price concession agreement denominated in U.S. dollars with the Ministry of Energy of Peru and the price is adjusted annually in accordance with the U.S. Consumer Price Index. We financed the acquisition with available cash on hand.

Cash flow

The following table sets forth cash flow data for the years ended December 31, 2017, 2016 and 2015:

	Year ended December 31, 2017	2016	2015
		$ in millions	
Gross cash flows from operating activities			
Profit/(loss) for the year	$ (104.9)	$ 1.6	$ (198.2)
Adjustments to reconcile after-tax profit to net cash generated by operating activities	848.8	664.8	734.9
Profit for the year adjusted by non-monetary items	**$ 743.9**	**$ 666.4**	**$ 536.7**
Net interest/taxes paid	(349.5)	(334.0)	(310.2)
Variations in working capital	(8.8)	2.0	73.1
Total net cash flow provided by/(used in) operating activities	**$ 385.6**	**$ 334.4**	**$ 299.6**
Net cash flows from investing activities			
Investments in entities under equity method	3.0	5.0	4.4
Investments in contracted concessional assets(1)	30.1	(6.0)	(106.0)
Other non-current assets/liabilities	8.2	(3.6)	5.7
Acquisitions / sales of subsidiaries and other financial instruments	30.1	(21.7)	(834.0)
Total net cash flows provided by/(used in) investing activities	**$ 71.4**	**$ (26.3)**	**$ (929.9)**
Net cash flows provided by/(used in) financing activities	**$ (416.3)**	**$ (226.1)**	**$ 810.9**
Net increase in cash and cash equivalents	**40.7**	**82.0**	**180.6**
Cash, cash equivalents and bank overdraft at beginning of the year	594.8	514.7	354.2
Translation differences cash or cash equivalents	33.9	(1.9)	(20.1)
Cash and cash equivalents at the end of the period	**$ 669.4**	**$ 594.8**	**$ 514.7**

Note:—

(1) Includes proceeds for $42.5 million and investments for $12.4 million. See note 6 of the Annual Consolidated Financial Statements.

Net cash flows provided by/(used in) operating activities

For the year ended December 31, 2017, net cash provided by operating activities was $385.6 million compared with $334.4 million for the year ended December 31, 2016, representing an increase of 15.3%. Profit adjusted by financial expenses and other non-monetary items was $743.9 million, an 11.6% increase year over year. Adjustments to reconcile after-tax profit to net cash generated by operating activities correspond mainly to depreciation, amortization and impairment expense and finance expenses partially offset by other non-monetary items, consisting mainly of income related to grants provided by the U.S. Treasury to Solana and Mojave. The $77.5 million increase in profit adjusted by financial expenses and other non-monetary items was mainly due to higher Further Adjusted EBITDA in 2017 in our Spanish solar assets due to higher remuneration and production. Variations in working capital in 2017 remained low compared to the previous year, since our working capital is generally stable on a yearly basis, with variations during the year due to seasonality. Net interest and taxes paid increased slightly by 4.6% to $349.5 million in the year ended December 31, 2017, mainly due to slightly higher interest rate of our corporate debt after we refinanced the short-term Tranche B of our Revolving Credit Facility with the Note Issuance Facility Agreement.

For the year ended December 31, 2016, net cash provided by operating activities was $334.4 million compared with $299.6 million for the year ended December 31, 2015, representing a 11.6% increase year over year. During the year ended December 31, 2016, profit adjusted by financial expense and non-monetary items was $666.4 million compared to $536.7 million for the year ended December 31, 2015. The increased profit adjusted by financial expense and non-monetary items was primarily due to the acquisition of Helios 1/2, Solnova 1/3/4, Helioenergy 1/2 and ATN2 in the second quarter of 2015 as well as Kaxu and Solaben 1/6 in the third quarter of 2015. All these assets are now generating a higher Further Adjusted EBITDA. Variations in working capital had a positive impact of $2.0 million in the year ended December 31, 2016. The variations in working capital for the year ended December 31, 2015 amounted to a positive $73.1 million mainly due to a reduction in short-term financial investments. Net interest and taxes paid increased to $334.0 million for the year ended December 31, 2016, from $310.2 million for the year ended December 31, 2015, mainly due to the net interest and taxes paid by the acquired assets mentioned above.

Net cash provided by/(used in) investing activities

For the year ended December 31, 2017, net cash provided by investing activities amounted to $71.4 million and corresponded mainly to $30.1 million of net proceeds received from the sale of the financial instruments received from Abengoa as part of the agreement related to the ACBH previously discussed, and $42.5 million received by Solana from Abengoa as a result of obligations as EPC contractor and pursuant to the consent signed with the DOE. Since the payment results from Abengoa's obligations under the construction contract, from an accounting perspective the payment is considered as lower consideration paid for the asset, reducing the asset value, and is classified as cash provided by investing activities. See "Item 5.—Operating and Financial Review and Prospects—A. Operating Results—Factors affecting our Results of Operations and the Comparability of our Results of Operations—Consent signed with the Department of Energy."

For the year ended December 31, 2016, net cash used in investing activities amounted to $26.3 million and corresponded mainly to the payments totaling $21.8 million for the pending payment of Solaben 1/6 and the acquisition of Seville PV.

For the year ended December 31, 2015, net cash used in investing activities amounted to $929.9 million principally due to the 2015 acquisitions under the Abengoa ROFO Agreement, net of the existing cash in the project companies acquired, for a net amount of $834.0 million.

Net cash provided by/(used in) financing activities

Net cash used in financing activities for the year ended December 31, 2017, amounted to $416.3 million and corresponded principally to $252.2 million of scheduled repayments of principal of our project financing agreements, $99.5 million of dividends paid to shareholders and non-controlling interest, $290.0 million of prepayment of Tranche B of the Revolving Credit Facility during the first quarter of 2017 and $71.0 million of partial prepayment of Tranche A of the Revolving Credit Facility during the third and fourth quarters of 2017. These cash outflows were offset mainly by $284.7 million of financing proceeds received under the Note Issuance Facility signed in the first quarter of 2017 and $11.7 million of financing proceeds received under a line of credit with a local bank signed in the third quarter of 2017.

Net cash used in financing activities for the year ended December 31, 2016, amounted to $226.1 million and corresponds mainly to the $182.6 million of principal debt repayment made by the assets, $35.5 million of dividends paid to shareholders and non-controlling interest and $19.7 million payment for acquisition of the 13% stake in Solacor 1/2 from the minority partner in the project (JGC), partially offset by $14.9 million of the proceeds of the refinancing in ATN2.

Net cash provided by financing activities for the year ended December 31, 2015 amounted to $810.9 million and corresponds mainly to the net proceeds of the capital increase that we closed in May 2015 pursuant to a private placement that resulted in the issuance of 20,217,260 new shares, with total net proceeds of $664.1 million. In addition, we made a drawing under Tranche B of our Revolving Credit Facility for a total amount of $286.0 million, net of expenses, which we used to finance the acquisition of the Fourth Dropdown Assets from Abengoa pursuant to the Abengoa ROFO Agreement. Furthermore, proceeds from project debt amounted to $173.4 million, related to the financing of scheduled pending payments from the construction phase of projects. These effects were partially offset by dividend payments to shareholders and non-controlling interest for a total amount of $137.2 million and the repayment of project debt of $175.4 million.

Financing Arrangements

2019 Notes

On November 17, 2014, we issued the 2019 Notes in an aggregate principal amount of $255 million. Interest accrues on the 2019 Notes from November 17, 2014 until November 15, 2019, the maturity date, at a rate of 7.000% per annum. The 2019 Notes were offered and issued in transactions exempt from registration to certain qualified institutional buyers in the United States, under Rule 144A under the Securities Act, and to institutional investors outside the United States, under Regulation S under the Securities Act.

The proceeds from the offering of the 2019 Notes were used, together with a portion of the proceeds of the Revolving Credit Facility, to finance the acquisition of the First Dropdown Assets from Abengoa pursuant to the Abengoa ROFO Agreement. See "Item 4.B—Business Overview—Our Growth Strategy—First Dropdown Assets." The total aggregate consideration for the First Dropdown Assets was $312 million (which consideration was determined in part by converting the portion of the purchase price of Solacor 1/2 and PS10/20 denominated in euros into U.S. dollars based on the exchange rate on the date on which the payment was made).

As of the date of this annual report, $255 million aggregate principal amount of the 2019 Notes remain outstanding. The 2019 Notes are guaranteed on a senior unsecured basis by our subsidiaries ASHUSA Inc., ASUSHI Inc., ABY South Africa (Pty) LTD, ABY Concessions Peru, S.A., ABY Concessions Infrastructures S.L.U. and ACT Holding, S.A. de C.V. If we fail to make payments on the 2019 Notes as required under the indenture governing such notes, the guarantors are obligated to make such payments.

The indenture governing the 2019 Notes provides, among other things, that the 2019 Notes and the guarantees are our and the guarantors', respectively, general unsecured obligations and rank equally (subject to any applicable statutory exemptions) in right of payment with all of our and the guarantors', respectively, existing and future debt that is not subordinated in right of payment and be effectively subordinated to all of our and the guarantors', respectively, existing and future secured debt to the extent of the assets securing such debt and to any preferential obligations under applicable law. Interest is payable on the 2019 Notes on May 15 and November 15 of each year beginning on May 15, 2015 until their maturity date of November 15, 2019.

The indenture governing the 2019 Notes contains covenants that limit certain of our and the guarantors' activities, including those relating to: incurring additional indebtedness; paying dividends on, redeeming or repurchasing our capital stock; prepaying subordinated indebtedness; making certain investments; imposing certain restrictions on the ability of subsidiaries to pay dividends or other payments; creating certain liens; transferring or selling assets; merging or consolidating with other entities; entering into transactions with affiliates; and engaging in unrelated businesses. Each of the covenants is subject to a number of important exceptions and qualifications. In addition, certain of the covenants listed above will terminate before the 2019 Notes mature if at least two of the specified rating agencies assign the 2019 Notes an investment grade rating in the future and no events of default under the indenture governing the 2019 Notes exist and are continuing. Any covenants that cease to apply to us as a result of achieving investment grade ratings will not be restored, even if the credit ratings assigned to the 2019 Notes later fall below investment grade.

The indenture governing the 2019 Notes also contains customary events of default (subject in certain cases to customary grace and cure periods). Generally, if an event of default occurs and is not cured within the time periods specified, the trustee or the holders of at least 25% in principal amount of the 2019 Notes then outstanding may declare all of the 2019 Notes to be due and payable immediately.

Revolving Credit Facility

On December 3, 2014, we, entered into a revolving credit facility of up to $125 million with HSBC Bank plc, as administrative agent, HSBC Corporate Trust Company (UK) Limited, as collateral agent and Banco Santander, S.A., Bank of America, N.A., Citigroup Global Markets Limited, HSBC Bank plc and RBC Capital Markets as joint lead arrangers and joint bookrunners, or the Revolving Credit Facility. We refer to the $125 million tranche of the Revolving Credit Facility as Tranche A. In 2017, we prepaid partially the principal outstanding under the Tranche A of the Revolving Credit Facility, leaving a balance of $54 million outstanding and $71 million of the Revolving Credit Facility was available at December 31, 2017. See “Item 5.B—Liquidity and Capital Resources—Financing Arrangements—Revolving Credit Facility.”

On June 26, 2015, we amended and restated our Revolving Credit Facility to include an additional revolving credit facility of up to $290 million with Bank of America, N.A., as global coordinator and documentation agent and Barclays Bank plc and UBS AG, London Branch as joint lead arrangers and joint bookrunners. We referred to the $290 million tranche of the Revolving Credit Facility as Tranche B. Tranche B was fully prepaid and canceled with the proceeds of the Note Issuance Facility.

Loans under Tranche A of the Revolving Credit Facility accrued interest at a rate per annum equal to: (A) for Eurodollar rate loans, LIBOR plus 2.75% and (B) for base rate loans, the highest of (i) the rate per annum equal to the weighted average of the rates on overnight U.S. Federal funds transactions with members of the U.S. Federal Reserve System arranged by U.S. Federal funds brokers on such day plus 1/2 of 1.00%, (ii) the U.S. prime rate and (iii) LIBOR plus 1.00%, in any case, plus 1.75%. The interest rate of the Revolving Credit Facility is hedged by an interest rate swap contracted with HSBC Bank with maturity date December 24, 2018, which fixes the interest rate at 4.7%. Loans under Tranche A of the Revolving Credit Facility mature on December 22, 2018. Loans prepaid by us under Tranche A of the Revolving Credit Facility may be reborrowed.

Loans under Tranche B of the Revolving Credit Facility accrued interest at a rate per annum equal to: (A) for Eurodollar rate loans, LIBOR plus 2.50% and (B) for base rate loans, the highest of (i) the rate per annum equal to the weighted average of the rates on overnight U.S. Federal funds transactions with members of the U.S. Federal Reserve System arranged by U.S. Federal funds brokers on such day plus 1/2 of 1.00%, (ii) the U.S. prime rate and (iii) LIBOR plus 1.00%, in any case, plus 1.50%.

Our payment obligations under the Revolving Credit Facility are guaranteed by our subsidiaries ASHUSA Inc., ASUSHI Inc., ABY South Africa (Pty) Ltd, ABY Concessions Peru S.A., ABY Concessions Infrastructures, S.L.U. and ACT Holding, S.A. de C.V. The Revolving Credit Facility is also secured by a high percentage of our assets and the assets of the guarantors, subject to customary exceptions.

The Revolving Credit Facility contains covenants that limit certain of our and the guarantors’ activities, including those relating to: mergers; consolidations; the ability to incur additional indebtedness; sales, transfers and other dispositions of property and assets; providing new guarantees; investments; granting additional security interests, transactions with affiliates and our ability to pay cash dividends is also subject to certain standard restrictions.

Additionally, we are required to comply with (i) a maintenance leverage ratio of our indebtedness at the holding level to our cash available for distribution of 5.00:1.00 on and after January 1, 2018 and (ii) an interest coverage ratio of cash available for distribution to debt service payments of 2.00:1.00.

The Revolving Credit Facility also contains customary events of default, the ability of the lenders to declare the unpaid principal amount of all outstanding loans, and interest accrued thereon, to be immediately due and payable. In addition, the Revolving Credit Facility includes a material subsidiary default provision related to a default by our project subsidiaries in their financing arrangements, such that a payment default by one or more of our non-recourse subsidiaries representing more than 20% of the cash available for distribution distributed in the previous four fiscal quarters could trigger a default under our Revolving Credit Facility.

Note Issuance Facility

On February 10, 2017, we entered into a senior secured note facility with U.S. Bank as agent and a group of funds managed by Westbourne Capital as purchasers of the notes issued thereunder for a total amount of € 275 million (approximately $330 million), or the Note Issuance Facility, with three series of notes. Series 1 notes worth €92 million mature in 2022; series 2 notes worth €91.5 million mature in 2023; and series 3 notes worth €91.5 million mature in 2024. Interest on all three series accrues at a rate per annum equal to the sum of three-month EURIBOR plus 4.90%. We fully hedged the Note Issuance Facility with a swap that fixed the interest rate at 5.5% immediately following the funding.

The obligations under the Note Issuance Facility rank *pari passu* with our outstanding obligations under Tranche A of the Revolving Credit Facility as well as the 2019 Notes. Our payment obligations under the Note Issuance Facility are guaranteed, collectively, by ASHUSA Inc., ASUSHI Inc., ABY South Africa (Pty) LTD, ABY Concessions Peru, S.A., ABY Concessions Infrastructures S.L.U. and ACT Holding, S.A. de C.V. The Note Issuance Facility is also secured by a high percentage of our assets and the assets of the guarantors, subject to customary exceptions.

The Note Issuance Facility contains covenants that limit certain of our and the guarantors' activities, including those relating to: mergers; consolidations; certain limitations on the ability to incur additional indebtedness; sales, transfers and other dispositions of property and assets; providing new guarantees; investments; granting additional security interests, transactions with affiliates and our ability to pay cash dividends is also subject to certain standard restrictions. Additionally, we are required to comply with (i) a maintenance leverage ratio of our indebtedness (including that of our subsidiaries) to our cash available for distribution of 5.00:1.00 on and after January 1, 2017, and of 4.75:1.00 on and after January 1, 2020, and (ii) a debt service coverage ratio of 2.00:1.00 of cash available for distribution to debt service payments.

The Note Issuance Facility also contains customary events of default, the ability of the lenders to declare the unpaid principal amount of all outstanding loans, and interest accrued thereon, to be immediately due and payable. In addition, our Note Issuance Facility includes a material subsidiary default provision such that a payment default by one or more of our non-recourse subsidiaries representing more than 20% of the cash available for distribution distributed in the previous four fiscal quarters could trigger a default, provided that these subsidiaries have an indebtedness higher than $100 million in the case of non-recourse subsidiaries or more than $75 million in the case of subsidiaries other than non-recourse subsidiaries.

We used the proceeds of the Note Issuance Facility to repay and cancel the Tranche B under our Revolving Credit Facility in March 2017.

Project level financing

We have outstanding project-specific debt that is backed by certain of our assets. These financing arrangements generally include a pledge of shares of the entities holding our assets and customary covenants, including restrictive covenants that limit the ability of the project-level entities to make cash distributions to their parent companies and ultimately to us including if certain financial ratios are not met. For more information about the debt of project-level entities, see "Item 4.B—Business Overview—Our Operations."

As we discuss in "Item 3.D—Risk Factors—Risks related to Our relationship with Abengoa," the financing arrangements of some of our project subsidiaries contain cross-default provisions related to Abengoa, such that debt defaults by Abengoa could trigger defaults under such project financing arrangements. In addition, some of our project financing arrangements contain a change of control provision that would be triggered if Abengoa ceases to own at least 35.0% of Atlantica Yield's shares.

During the years 2015, 2016 and 2017, waivers and forbearances were obtained for most of our project financing agreements from all the parties of these project financing arrangements containing such covenants.

In March 2017, we obtained a waiver in our Kaxu project financing arrangement of any potential cross-defaults with Abengoa up to that date, but it does not cover potential future cross-default events.

In the case of Solana and Mojave, a forbearance agreement signed with the DOE in 2016 with respect to these assets allows reductions of Abengoa's ownership of our shares if it results from (i) a sale or other disposition at any time pursuant to and in connection with a subsequent insolvency proceeding by Abengoa, or (ii) capital increases by us. In other events of reduction of ownership by Abengoa below the minimum ownership threshold such as sales of shares by Abengoa, the available DOE remedies will not include debt acceleration, but DOE remedies available could include limitations on distributions to us from Solana and Mojave. In addition, the minimum ownership threshold for Abengoa's ownership of our shares has been reduced from 35.0% to 30.0%. In November 2017, in the context of the agreement reached between Abengoa and Algonquin for the acquisition by Algonquin of 25.0% of our shares and based on the obligations of Abengoa under an EPC contract, we signed a consent in relation to the Solana and Mojave projects which reduces the minimum ownership required by Abengoa in us from 30.0% to 16.0%, subject to certain conditions precedent. In Solana, the EPC guarantee period expired without reaching the expected production. As the EPC supplier, Abengoa agreed to provide certain compensations. As a result, the main conditions precedent included several payments by Abengoa to Solana before December 2017 and February 2018 (subsequently postponed to May 2018), for a total amount of $120 million. Additionally, Abengoa has recognized other obligations with Solana for $6.5 million per half-year over 10 years starting in December 2018. In December 2017, Solana received $42.5 million which was used to repay project finance debt. Solana is expected to receive in March 2018 an additional $77.5 million. From this amount $52.5 million are expected to be used to repay project debt and $25 million are expected to cover other current and potential future Abengoa obligations.

In addition, in 2017, Kaxu's debt coverage ratio did not reach the minimum threshold due to the technical problems that the plant experienced since the end of 2016, and the lenders of the project finance agreement granted a waiver to the asset.

Critical Accounting Policies and Estimates

The preparation of our Annual Consolidated Financial Statements in conformity with IFRS requires us to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses. We base our estimates on historical experience and on various other assumptions we believe to be reasonable under the specific circumstances, the results of which form the basis for making judgments about the carrying values of assets and liabilities that are not readily apparent from other sources. Actual results may differ from these estimates under different assumptions or conditions.

An understanding of the accounting policies for these items is important to understand the Annual Consolidated Financial Statements. The following discussion provides more information regarding the estimates and assumptions used for these items in accordance with IFRS and should be considered in conjunction with the Annual Consolidated Financial Statements.

The most critical accounting policies, which reflect significant management estimates and judgment to determine amounts in our Annual Consolidated Financial Statements, are as follows:

- Contracted concessional agreements and PPAs;

- Impairment of intangible assets and property, plants and equipment;

- Assessment of control;
- Derivative financial instruments and fair value estimates; and
- Income taxes and recoverable amount of deferred tax assets.

Some of these accounting policies require the application of significant judgment by management to select the appropriate assumptions to determine these estimates. These assumptions and estimates are based on our historical experience, forecasts and other circumstances and expectations as of the close of the financial period. The assessment is considered in relation to the global economic situation of the industries and regions where we operate, taking into account future development of our businesses. By their nature, these judgments are subject to an inherent degree of uncertainty; therefore, actual results could materially differ from the estimates and assumptions used. In such cases, the carrying values of assets and liabilities are adjusted.

As of the date of preparation of our Annual Consolidated Financial Statements, no relevant changes in the estimates made are anticipated and, therefore, no significant changes in the value of the assets and liabilities recognized at December 31, 2017, are expected.

Although these estimates and assumptions are being made using all available facts and circumstances, it is possible that future events may require management to amend such estimates and assumptions in future periods. Changes in accounting estimates are recognized prospectively, in accordance with IAS 8, in the consolidated income statement of the year in which the change occurs. Our significant accounting policies are more fully described in note 2 to our Annual Consolidated Financial Statements, presented elsewhere in this annual report.

Contracted concessional agreements

Contracted concessional assets include fixed assets financed through non-recourse loans, related to service concession arrangements recorded in accordance with IFRIC 12, except for Palmucho, which is recorded in accordance with IAS 17, PS10/20 and Seville PV, which are recorded as tangible assets in accordance with IAS 16. The infrastructures accounted for as concessions are related to the activities concerning electric transmission lines, solar electricity generation plants, cogeneration plants, wind farms and water desalination plants. The infrastructure used in a concession can be classified as an intangible asset or a financial asset, depending on the nature of the payment entitlements established in the agreement.

The application of IFRIC 12 requires extensive judgment in relation with, among other factors, (i) the identification of certain infrastructures and contractual agreements in the scope of IFRIC 12, (ii) the understanding of the nature of the payments in order to determine the classification of the infrastructure as a financial asset or as an intangible asset and (iii) the timing and recognition of the revenue from construction and concessionary activity.

Under the terms of contractual arrangements within the scope of this interpretation, the operator shall recognize and measure revenue in accordance with IAS 11 and 18 for the services it performs. If the operator performs more than one service (i.e., construction or upgrade services and operation services) under a single contract or arrangement, consideration received or receivable shall be allocated by reference to the relative fair values of the services delivered, when the amounts are separately identifiable.

Intangible assets

We recognize an intangible asset to the extent that we receive a right to charge final customers for the use of the infrastructure. This intangible asset is subject to the provisions of IAS 38 and is amortized linearly, taking into account the estimated period of commercial operation of infrastructure, which generally coincides with the concession period.

Once the infrastructure is in operation, the treatment of income and expenses is as follows:

- Revenues from the updated annual revenue for the contracted concession, as well as operations and maintenance services are recognized in each period according to IAS 18 “Revenue.”

- Operating and maintenance costs and general overheads and administrative costs are recorded in accordance with the nature of the cost incurred (amount due) in each period.

- Financing costs are expensed as incurred.

Financial assets

We recognize a financial asset when demand risk is assumed by the grantor, to the extent that the contracted concession holder has an unconditional right to receive payments for the asset. This asset is recognized at the fair value of the construction services provided, considering upgrade services in accordance with IAS 11, if any.

The financial asset is subsequently recorded at amortized cost calculated according to the effective interest method. Revenue from operations and maintenance services is recognized in each period according to IAS 18 “Ordinary income.” The remuneration of managing and operating the asset resulting from the valuation at amortized cost is also recorded in revenue.

Financing costs are expensed as incurred.

Property, plant and equipment

Assets recorded as property, plant and equipment (PS10/20 and Seville PV) are measured at historical cost, including all expenses directly attributable to the acquisition, less depreciation and impairment losses, with the exception of land, which is presented net of any impairment losses. Once the infrastructure is in operation, the treatment of income and expenses is equal to intangible assets.

Impairment of intangible assets and property, plant and equipment

We review our contracted revenue assets to identify any indicators of impairment annually.

The recoverable amount of an asset is the higher of its fair value less costs to sell and its value in use, defined as the present value of the estimated future cash flows to be generated by the asset. In the event that the asset does not generate cash flows independently of other assets, we calculate the recoverable amount of the cash generating unit, or CGU to which the asset belongs.

When the carrying amount of the CGU to which these assets belong is lower than its recoverable amount assets are impaired.

Assumptions used to calculate value in use include a discount rate and projections considering real data based on the contract terms and projected changes in both selling prices and costs. The discount rate is estimated by management, to reflect both changes in the value of money over time and the risks associated with the specific CGU.

For contracted or concession revenue assets with a defined useful life and with a specific financial structure, cash flow projections until the end of the project are considered and no terminal value is assumed. Contracted revenue assets have a contractual structure that permits to estimate quite accurately the costs of the project (both in the construction and in the operations periods) and revenue during the life of the project.

Projections take into account real data based on the contract terms and fundamental assumptions based in specific reports prepared by experts, assumptions on demand and assumptions on production. Additionally, assumptions on macroeconomic conditions are also taken into account, such as inflation rates, future interest rates and sensitivity analysis are performed over all major assumptions, which can have a significant impact on the value of the asset.

Cash flow projections of CGUs are calculated in the functional currency of those CGUs and are discounted using rates that take into consideration the risk corresponding to each specific country and currency.

Taking into account that in most CGUs its specific financial structure is linked to the financial structure of the projects that are part of those CGUs, the discount rate used to calculate the present value of cash flow projections is based on the weighted average cost of capital, or WACC, for the type of asset, adjusted, if necessary, in accordance with the business of the specific activity and with the risk associated with the country where the project is performed. In any case, sensitivity analyses are performed, especially in relation with the discount rate used and fair value changes in the main business variables, in order to ensure that possible changes in the estimates of these items do not impact the possible recovery of recognized assets. See note 2 to our Annual Consolidated Financial Statements for further information on WACCs.

In the event that the recoverable amount of an asset is lower than its carrying amount, an impairment charge for the difference would be recorded in the consolidated income statement under the item “depreciation, amortization and impairment charges.”

We identified a triggering event of impairment for Solana as a result of the generation of the plant having been lower than expected during 2017 related to an incident with electric transformers which took place in July 2017. This project is within the Renewable energy sector and North America geography. We therefore performed an impairment test as of December 31, 2017, which resulted in the recoverable amount (value in use) exceeding the carrying amount of the asset by 7%. To determine the value in use of the asset, a specific discount rate has been used in each year considering changes in the debt/equity leverage ratio over the useful life of this project, resulting in the use of a range of discount rates between 4.7% and 5.0%. An adverse change in the key assumptions which are individually used for the valuation would not lead to future impairment recognition; neither in case of a 5% decrease in generation over the entire remaining useful life (PPA) of the project nor in case of an increase of 50 basis points in the discount rate.

Assessment of control

Control over an investee is achieved when we have power over the investee, we are exposed, or have rights, to variable returns from our involvement with the investee and have the ability to use its power to affect its returns. We reassess whether or not we control an investee when facts and circumstances indicate that there are changes to one or more of these three elements of control.

We use the acquisition method to account for business combinations of companies controlled by a third party. According to this method, identifiable assets acquired and liabilities and contingent liabilities assumed in a business combination are measured initially at their fair values at the acquisition date. Any contingent consideration is recognized at fair value at the acquisition date and subsequent changes in its fair value are recognized in accordance with IAS 39 either in profit or loss or as a change to other comprehensive income. Acquisition-related costs are expensed as incurred. We recognize any non-controlling interest in the acquired entity either at fair value or at the non-controlling interest’s proportionate share of the acquirer’s net assets on an acquisition-by-acquisition basis.

All assets and liabilities between entities within the group, equity, income, expenses and cash flows relating to transactions between entities of the group are eliminated in full.

Derivative financial instruments and fair value estimates

Derivatives are recorded at fair value. We apply hedge accounting to all hedging derivatives that qualify to be accounted for as hedges under IFRS.

When hedge accounting is applied, hedging strategy and risk management objectives are documented at inception, as well as the relationship between hedging instruments and hedged items. Effectiveness of the hedging relationship needs to be assessed on an ongoing basis. Effectiveness tests are performed prospectively and retrospectively at inception and at each reporting date, following the dollar offset method.

We apply cash flow hedge accounting. Under this method, the effective portion of changes in fair value of derivatives designated as cash flow hedges are recorded temporarily in equity and are subsequently reclassified from equity to profit or loss in the same period or periods during which the hedged item affects profit or loss. Any ineffective portion of the hedged transaction is recorded in the consolidated income statement as it occurs.

When interest rate options are designated as hedging instruments, the intrinsic value and time value of the financial hedge instrument are separated. Changes in intrinsic value which are highly effective are recorded in equity and subsequently reclassified from equity to profit or loss in the same period or periods during which the hedged item affects profit or loss. Changes in time value are recorded as financial income or expenses, together with any ineffectiveness.

When the hedging instrument matures or is sold, or when it no longer meets the requirements to apply hedge accounting, accumulated gains and losses recorded in equity remain as such until the forecast transaction is ultimately recognized in the income statement. However, if it becomes unlikely that the forecast transaction will actually take place, the accumulated gains and losses in equity are recognized immediately in the income statement.

The inputs used to calculate fair value of our derivatives are based on inputs other than quoted prices that are observable for the asset or liability, either directly (i.e., as prices) or indirectly (i.e., derived from prices), through the application of valuation models (Level 2). The valuation techniques used to calculate fair value of our derivatives include discounting estimated future cash flows, using assumptions based on market conditions at the date of valuation or using market prices of similar comparable instruments, amongst others. The valuation of derivatives requires the use of considerable professional judgment. These determinations were based on available market information and appropriate valuation methodologies. The use of different market assumptions and/or estimation methodologies may have a material effect on the estimated fair value amounts.

Income taxes and recoverable amount of deferred tax assets

The current income tax provision is calculated on the basis of relevant tax laws in force at the date of the statement of financial position in the countries in which the subsidiaries and associates operate and generate taxable income.

Determining income tax payable requires judgment in assessing the timing and the amount of deductible and taxable items, as well as the interpretation and application of tax laws in different jurisdictions. Due to this fact, contingencies or additional tax expenses could arise as a result of tax inspections or different interpretations of certain tax laws by the corresponding tax authorities.

We recognize deferred tax assets for all deductible temporary differences and all unused tax losses and tax credits to the extent that it is probable that future taxable profit will be available against which they can be utilized.

We consider it probable that we will have sufficient taxable profit available in the future to enable a deferred tax asset to be recovered when:

- There are sufficient taxable temporary differences relating to the same tax authority, and the same taxable entity is expected to reverse either in the same period as the expected reversal of the deductible temporary difference or in periods into which a tax loss arising from the deferred tax asset can be carried back or forward.

- It is probable that the taxable entity will have sufficient taxable profit, relating to the same tax authority and the same taxable entity, in the same period as the reversal of the deductible temporary difference (or in the periods into which a tax loss arising from the deferred tax asset can be carried back or forward).

- Tax planning opportunities are available to the entity that will create taxable profit in appropriate periods.

Our management assesses the recoverability of deferred tax assets on the basis of estimates of future taxable profit. These estimates are derived from the projections of each of our assets. Based on our current estimates, we expect to generate sufficient future taxable income to achieve the realization of our current tax credits and tax loss carryforwards, supported by our historical trend of business performance.

In assessing the recoverability of our deferred tax assets, our management also considers the foreseen reversal of deferred tax liabilities and tax planning strategies. To the extent management relies on deferred tax liabilities for the readability of our deferred tax assets, such deferred tax liabilities are expected to reverse in the same period and jurisdiction and are of the same character as the temporary differences giving rise to the deferred tax assets. We consider that the recovery of our current deferred tax assets is probable without counting on potential tax planning strategies that we could use in the future.

C. Research and Development

Not applicable.

D. Trend Information

Other than as disclosed elsewhere in this annual report, we are not aware of any trends, uncertainties, demands, commitments or events for the year ended December 31, 2017 that are reasonably likely to have a material adverse effect on our revenues, income, profitability, liquidity or capital resources, or that caused the disclosed financial information to be not necessarily indicative of future operating results or financial conditions.

E. Off-Balance Sheet Arrangements

As of December 31, 2017, our only off-balance sheet arrangements consisted of bank guarantee and surety insurance in an aggregate amount of $32.4 million attributed to transactions of a technical nature. In addition, in the third quarter of 2017, we issued guarantees of a technical nature in the amount of $112 million previously provided by Abengoa. For further discussion, see note 19 to our Annual Consolidated Financial Statements included elsewhere in this annual report.

F. Tabular Disclosure of Contractual Obligations

The following table summarizes our contractual obligations as of December 31, 2017.

	Total	Up to one year	Between one and three years	Between three and five years	Subsequent years
			$ in millions		
Corporate debt	$ 643.1	$ 68.9	$ 253.4	$ 107.3	$ 213.5
Loans with credit institutions (project debt)	4,628.3	215.1	457.9	539.4	3,415.9
Notes and bonds (project debt)	846.9	31.2	53.6	54.4	707.7
Purchase commitments	3,149.8	141.9	230.0	259.8	2,518.1
Accrued interest estimate during the useful life of loans	3,129.3	340.5	630.1	559.9	1,598.9

As described in the table above, we have other contractual obligations to make future payments in connection with bank debt and notes and bonds. In addition, during the normal course of business, we enter into agreements where we commit to future purchases of goods and services from third parties.

Corporate debt refers to the 2019 Notes, the Revolving Credit Facility, the Note Issuance Facility and a credit facility with a local bank, which are described in detail in note 14 to our Annual Consolidated Financial Statements.

For more detailed information on project debt (loans with credit institutions) refer to note 15 to our Annual Consolidated Financial Statements.

Notes and bonds refer to the carrying value of issuances made at ATS, ATN, ATN2 and Solaben 1/6.

Purchase obligations include agreements for the purchase of goods or services that are enforceable and legally binding on the combined group and that specify all significant terms, including fixed or minimum quantities to be purchased, fixed, minimum or variable price provisions and the appropriate timing of the transactions.

Accrued interest estimate during the useful life of loans represents the estimation for the total amount of interest to be paid or accumulated over the useful life of the loans, notes and bonds.

Capital Expenditures

Our capital spending program is limited considering all our projects are in operation.

G. Safe Harbor

This annual report contains forward-looking statements within the meaning of Section 27A of the Securities Act and Section 21E of the Exchange Act and as defined in the Private Securities Litigation Reform Act of 1995. See “Cautionary Statements Regarding Forward-Looking Statements.”

ITEM 6. DIRECTORS, SENIOR MANAGEMENT AND EMPLOYEES

A. Directors and Senior Management

Board of Directors of Atlantica Yield

The board of directors of Atlantica Yield comprises the following eight members:

Name	Position	Year of birth
Daniel Villalba	Director and Chairman of the Board	1947
Santiago Seage	Chief Executive Officer and Director	1969
Joaquin Fernandez de Pierola	Director	1971
Gonzalo Urquijo	Director	1961
Jack Robinson	Director	1942
Robert Dove	Director	1954
Andrea Brentan	Director	1949
Francisco J. Martinez	Director	1958

The business address of the members of the board of directors of Atlantica Yield is Great West House, GW1, 17 floor, Great West Road, Brentford, United Kingdom, TW8 9DF.

There are no family relationships among any of our executive officers or directors. There are no potential conflicts of interest between the private interests or other duties of the members of the board of directors listed above and their duties to Atlantica Yield, except in the case of Santiago Seage, who serves as the Chief Executive Officer of Atlantica Yield. Additionally, Gonzalo Urquijo serves as the executive chairman of Abengoa and Joaquin Fernandez de Pierola serves as Chief Executive Officer at Abengoa.

The following is the biographical information of members of our board of directors.

Daniel Villalba, Director and Chairman of the Board

Daniel Villalba has served as a director since our formation in 2014. Mr. Villalba was previously a Professor of Business Economics at the Universidad Autonoma de Madrid. He also previously served as the CEO of Inverban, a broker and investment bank, and independent board member of Vueling, an airline currently part of International Airlines Group, Abengoa and the Madrid Stock Exchange, as well as a board member of several private companies. He also has written more than 50 academic papers and books. Mr. Villalba holds a Master of Science in Operations Research from Stanford University, a Master of Science in Business Administration from the University of Massachusetts and a PhD in Economics from the Universidad Autonoma de Madrid. Mr. Villalba was elected chairman of the board on November 27, 2015.

Santiago Seage, Chief Executive Officer and Director

Mr. Seage has served as a director since our formation in 2014 and was Chairman from June until November 2015. Mr. Seage served as our Chief Executive Officer from our formation until he was appointed Chief Executive Officer of Abengoa in May 2015, in which capacity he served until November 27, 2015, when he was appointed as our Managing Director. Mr. Seage was elected to Chief Executive Officer on May 11, 2016. Prior to the foregoing, he served as Abengoa Solar's CEO beginning in 2006. Before joining Abengoa, he was a partner with McKinsey & Company. Mr. Seage holds a degree in Business Management from ICADE University in Madrid.

Joaquin Fernandez de Pierola, Director

Mr. Fernandez de Pierola has served as a director since November 2016. Mr. Fernandez de Pierola currently serves as CEO of Abengoa. He holds a Bachelor of Science in Economics and Business from the University of Zaragoza. He later specialized in Market Research at the University of West England in Bristol and completed the General Management Program at IESE Business School in Barcelona. After serving for several years in the public sector, Mr. Fernandez de Pierola has held different positions in commercial and concessions fields at gHT and Befesa Agua. Afterwards, he became Business Development VP for Middle East and Asia in Abengoa's Engineering and Construction business unit before serving as Chairman and CEO of Abengoa Mexico.

Jack Robinson, Director

Mr. Robinson has served as a director since our formation in 2014. Mr. Robinson is Vice Chairman and Portfolio Manager at Trillium Asset Management. He also serves on the advisory board of several institutions including ACORE (American Council on Renewable Energy), EFW (Energy, Food & Water) and Bambeco (Sustainable Housewares). He holds a Bachelor's degree from Brown University.

Gonzalo Urquijo, Director

Mr. Urquijo is currently the Executive Chairman of Abengoa and is a Director of Gestamp, Vocento and Fertiberia. Mr. Urquijo graduated from Yale in Economics and has an MBA from Instituto de Empresa. He began his career in the banking sector, first at Citigroup and then at Credit Agricole. From 1992 to 2017, he has been in the steel industry and has also been a member of the General Management Board in ArcelorMittal.

Robert Dove, Director

Mr. Dove serves as a Senior Advisor of the Carlyle Group. Previously, he was a partner, managing director and a co-head of Carlyle Infrastructure Fund. He also held various positions at Bechtel Group Inc. and UBS Securities.

Andrea Brentan, Director

Mr. Brentan has extensive experience in the power sector. He currently serves as a senior advisor to Bain Capital and as non-executive chairman of FTI Consulting in Spain. Prior to that, he was CEO of Endesa, an international utility, from 2009 to 2014. Mr. Brentan has also held different executive positions at Entel, Alstom Power and ABB.

Francisco J. Martinez, Director

Mr. Francisco J. Martinez has more than 30 years of experience as a certified public accountant. Until 2013, Mr. Martinez was a partner at PWC in charge of the Energy sector, including audit, legal and tax. He also served as the deputy director for economy at the energy regulator of Spain (CNE) between 1995 and 1998.

Senior Management of Atlantica Yield

We have a senior management team with extensive experience in developing, financing, managing and operating contracted assets.

Our senior management is made up of the following members:

Name	Position	Year of birth
Santiago Seage	Chief Executive Officer and Director	1969
Francisco Martinez-Davis	Chief Financial Officer	1963
Manuel Silvan	Vice President Taxes, Risk Management and Compliance	1973
Emiliano Garcia	Vice President North America	1968
Antonio Merino	Vice President South America	1967
David Esteban	Vice President EMEA	1979
Irene M. Hernandez	General Counsel	1980
Stevens C. Moore	Vice President Strategy and Corporate Development	1973

The business address of the members of the senior management of Atlantica Yield is Great West House, GW1, 17 floor, Great West Road, Brentford, United Kingdom, TW8 9DF.

There are no potential conflicts of interest between the private interests or other duties of the members of the senior management listed above and their duties to Atlantica Yield. There are no family relationships among any of our executive officers or directors.

Below are the biographies of those members of the senior management of Atlantica Yield who do not also serve on our board of directors.

Francisco Martinez-Davis, Chief Financial Officer

Mr. Martinez-Davis was appointed as our Chief Financial Officer on January 11, 2016. Mr. Martinez-Davis has more than 25 years of experience in senior finance positions both in the United States and Spain. He has served as Chief Financial Officer of several large industrial companies. Most recently, he was Chief Financial Officer for the company responsible for the management and operation of metropolitan rail service of the city of Madrid where he was also member of the Executive Committee. He has also worked as CFO for a retailer and as Deputy General Manager in Finance and Treasury for Telefonica Moviles. Prior to that, he worked for different investment banks in New York City and London for more than 10 years, including J.P. Morgan Chase & Co. and BNP Paribas. Mr. Martinez-Davis holds a Bachelor of Science, cum laude, in Business Administration from Villanova University in Philadelphia and an MBA from The Wharton School at the University of Pennsylvania.

Manuel Silvan, Vice President Taxes, Risk Management and Compliance

Mr. Silvan has served as Vice President Taxes, Risk Management and Compliance since our formation. Prior to that, he served as Abengoa's Vice President of Taxation beginning in 2007. Before joining Abengoa in 1998, he worked for the legal and tax advisory firm of Garrigues. Mr. Silvan holds a degree in Economics and Business Science from Huelva University, a Master's degree in Tax Consultancy from Cajasol Business Institute and an MBA from San Telmo International Institute.

Emiliano Garcia, Vice President North America

Mr. Garcia serves as Vice President of our North American business. Based in Phoenix, Arizona, he is responsible for managing two of our key assets, Solana and Mojave. Mr. Garcia was previously the General Manager of Abengoa Solar in the United States and of the Solana Power Plant. Before that, he held a number of managerial positions in various Abengoa companies over two decades. Mr. Garcia holds a Bachelor's degree in Engineering from Madrid Technical University.

Antonio Merino, Vice President South America

Mr. Merino serves as Vice President of our South American business. Previously, he was the Vice President of Abengoa's Brazilian business, as well as the head of Abengoa's commercial activities and partnerships in South America. Mr. Merino holds an MBA from San Telmo International Institute.

David Esteban, Vice President EMEA

Mr. Esteban has served as Vice President of our operations in EMEA since July 2014. He had previously served at Abengoa's Corporate Concession department for two years. Before joining Abengoa, David worked for the management consulting firm Arthur D. Little for seven years in the industries of Telecoms & Energy and then moved to a private equity firm specialized in renewable investments in Europe for three years.

Irene M. Hernandez, General Counsel

Ms. Hernandez has served as our General Counsel since June 2014. Prior to that, she served as head of our legal department since the date of our formation. Before that, Ms. Hernandez served as Deputy Secretary General at Abengoa Solar since 2012. Before joining Abengoa, she worked for several law firms. Ms. Hernandez holds a law degree from Complutense Madrid University and a Master's degree in law from the Madrid Bar Association (Colegio de Abogados de Madrid (ICAM)).

Stevens C. Moore, Vice President Strategy & Corporate Development

Mr. Moore has more than 22 years of experience in finance positions in Spain, the United Kingdom and the United States. He has worked in various positions in structured and leveraged finance at Citibank and Banco Santander, and vice president of M&A at GBS Finanzas. Most recently, he was director of corporate development and investor relations at Codere, the Madrid stock exchange listed international gaming company. He holds a B.A. degree in history from Tulane University of New Orleans, Louisiana.

Lead Independent Director

Our corporate governance guidelines provide that one of our independent directors shall serve as a lead independent director at any time when an independent director is not serving as the chairman of our board of directors. Mr. Villalba served as our lead independent director until he was named chairman of our board of directors on November 27, 2015, a position he holds until today.

B. Compensation

Compensation of Board of Directors and Chief Executive Officer

Our independent directors will receive compensation as "non-employee directors" as set by our board of directors.

Each independent director received in 2017 a total annual compensation of $100,000. As chairman of the board of directors, Mr. Villalba received an additional $35,000 per year. Non-executive directors appointed by Abengoa do not receive any compensation from us.

In 2016, we adopted our long-term incentive plan for management, or Long-Term Incentive Plan, for the period from 2016 to 2019. Twelve executives, including our CEO, are eligible under the Long-Term Incentive Plan. The number of participants could increase if approved by the board and the Long-Term Incentive Plan provides that each eligible executive would be entitled to the payment of a long-term incentive cash bonus in March 2019 if we have achieved our Total Annual Shareholder's Return, or TSR, objectives over the 2016-19 period, a metric intended to align management and shareholder interests. The maximum bonus will be 50% (or, in the CEO's case, 70%) of the total remuneration received by the executive over the period from 2016-18. Specifically, 50% of the bonus will be based on our TSR and 50% on the relative performance in terms of TSR versus a group of similarly structured companies selected by the Compensation Committee. In case of a change of control, the long-term incentives would become due and would be calculated using the offer price or the last price based on TSR up to and including the change of control.

The total compensation received by our independent directors and Chief Executive Officer from us during 2017 is set forth in the table below.

	Directors, Remuneration for the year ended December 31, 2017					
	Salary and Fees	All Taxable Benefits	Annual Bonuses	LTIP	Pension	Total
			(in thousands of U.S. dollars)			
Santiago Seage	677.8	-	924.2	-	-	1,602.0
Daniel Villalba	135.0	-	-	-	-	135.0
Jack Robinson	100.0	-	-	-	-	100.0
Enrique Alarcon(1)	50.0	-	-	-	-	50.0
Eduardo Kausel(2)	50.0	-	-	-	-	50.0
Juan del Hoyo(3)	50.0	-	-	-	-	50.0
Robert Dove(4)	50.0	-	-	-	-	50.0
Andrea Brentan(5)	50.0	-	-	-	-	50.0
Francisco J. Martinez(6)	50.0	-	-	-	-	50.0
Gonzalo Urquijo(7)	-	-	-	-	-	-
Maria Jose Esteruelas(8)	-	-	-	-	-	-
Joaquin Fernandez de Pierola(9)	-	-	-	-	-	-
Total	**1,212.8**	**-**	**924.2**	**-**	**-**	**2,137.0**

Notes:—

(1) Resigned on June 23, 2017.
(2) Resigned on June 23, 2017.
(3) Resigned on June 23, 2017.
(4) Appointed on June 23, 2017.
(5) Appointed on June 23, 2017.
(6) Appointed on June 23, 2017.
(7) Appointed on November 22, 2017.
(8) Replaced on November 22, 2017.
(9) Appointed on June 23, 2017.

Each member of our board of directors will be indemnified for his actions associated with being a director to the extent permitted by law.

C. Board Practices

Our board of directors consists of eight directors, five of whom are independent. Under our articles of association, our board may consist of 7 to 13 members. Additionally, our articles of association established a term of office of up to 3 years. Our current directors have been serving since 2014, except for Joaquin Fernandez de Pierola, who was appointed in 2016, and Robert Dove, Andrea Brentan, Francisco J. Martinez and Gonzalo Urquijo, who were appointed in 2017.

Directors affiliated with Abengoa do not vote on matters that represent or could represent a conflict of interests, including the evaluation of assets offered to us under the AAGES, Algonquin and Abengoa ROFO Agreements. Directors affiliated with AAGES and Algonquin will not vote on matters that represent or could represent a conflict of interests, including the evaluation of assets offered to us under the AAGES, Algonquin and Abengoa ROFO Agreements. See “Item 7.B—Related Party Transactions—Procedures for Review, Approval and Ratification of Related Party Transactions; Conflicts of Interest.”

Our board of directors is responsible for, among other things, overseeing the conduct of our business; reviewing and, where appropriate, approving, our long-term strategic, financial and organizational goals and plans; and reviewing the performance of our chief executive officer and other members of senior management.

Under English law, the board of directors of an English company is responsible for the management, administration and representation of all matters concerning the relevant business, subject to the company's corporate constitution. Under English law and our constitution, the board of directors may delegate its powers to an executive committee or other delegated committee or to one or more persons.

Audit Committee

Our Audit Committee is responsible for monitoring and informing the board of directors on the work of external and internal auditors, control systems, key processes and procedures, security and risks. The committee comprises the following three members, each of whom is an independent director:

Name	Position
Francisco J. Martinez	Chairman
Daniel Villalba	Member
Jack Robinson	Member

The committee will meet as many times as required and a minimum of two times per year.

Our Audit Committee is directly responsible for overseeing the work of the external auditor engaged for the purpose of preparing or issuing an auditor's report or performing other audit, review or attest services, including the resolution of disagreements between the external auditor and management. The external auditor will report directly to our Audit Committee. Our Audit Committee is also responsible for reviewing and approving our hiring policies regarding former employees of the external auditor. In addition, the Audit Committee preapproves all non-audit services undertaken by the external auditor.

Our Audit Committee is responsible for reviewing the adequacy and security of procedures for the confidential, anonymous submission by our employees or contractors regarding any possible wrongdoing in financial reporting or other matters. Our Audit Committee is accountable to our board of directors and will provide a report to our board of directors after each regularly scheduled Audit Committee meeting outlining the results of the Audit Committee's activities and proceedings.

Nominating and Corporate Governance Committee

Our Nominating and Corporate Governance Committee comprises the following three members, two of whom are independent directors (Gonzalo Urquijo is affiliated to Abengoa).

Name	Position
Robert Dove	Chairman
Daniel Villalba	Member
Gonzalo Urquijo	Member

The duties and functions of our Nominating and Corporate Governance Committee include, among others, regularly reviewing the structure, size and composition (including the skills, knowledge, experience and diversity) of the board of directors and make recommendations to the board of directors with regard to any changes, and keep under review corporate governance rules and developments (including ethics-related matters) that might affect us, with the aim of ensuring that our corporate governance policies and practices continue to be in line with best practice. Our Nominating and Corporate Governance Committee meets at least twice a year at appropriate intervals in the financial reporting and audit cycle and otherwise as required. The committee informs and makes proposals to the board of directors.

Compensation Committee

Our Compensation Committee comprises the following three members, each of whom is an independent director:

Name	Position
Jack Robinson	Chairman
Andrea Brentan	Member
Robert Dove	Member

The duties and functions of our Compensation Committee include, among others, analyze, discuss and make recommendations to the board of directors regarding the setting of the remuneration policy for all directors as well as senior management, including pension rights and any compensation. The committee meets at least twice a year at appropriate intervals in the financial reporting and audit cycle and otherwise as required. The committee informs and makes proposals to the board of directors.

Related Party Transaction Committee

Our Related Party Transaction Committee comprises the following five members, each of whom is an independent director:

Name	Position
Daniel Villalba	Chairman
Jack Robinson	Member
Andrea Brentan	Member
Robert Dove	Member
Francisco Jose Martinez	Member

The duties and functions of our Related Party Transaction Committee include, among others, evaluating on an ongoing basis existing relationships between and among businesses and counterparties to ensure that all related parties are identified, monitoring related-party transactions, identifying changes in relationships with counterparties and overseeing the implementation of a system for identifying, monitoring and reporting related-party transactions, including a periodic review of such transactions, applicable policies and procedures.

The Related Party Transaction Committee shall meet at such times as required and where it considers appropriate. The Related Party Transaction Committee will report to the board of directors on the decisions and recommendations made by the committee, including but not limited to any conflict of interest and any procedure to manage such conflict of interest.

D. Employees

The following table shows the number of employees as of December 31, 2017, 2016 and 2015, on a consolidated basis:

Geography	Year ended December 31,		
	2017	2016(1)	2015(1)
EMEA	56	53	40
North America	28	28	8
South America	15	9	6
Corporate	86	85	41
Total	**185**	**175**	**95**

Note:—

(1) Prior period numbers have been adjusted to conform current calculation method.

The increase in the number of employees for the year ended December 31, 2016 as compared to the year ended December 31, 2015 is mainly due to the transfer of employees previously employed by subsidiaries of Abengoa who were providing services to us under the support services agreement to our subsidiaries. The transfer occurred over the first six months of 2016 and the support service agreement was terminated in the second quarter of 2016.

E. Share Ownership

None of our directors or members of our senior management is the owner of more than one percent of our ordinary shares, and no director or member of our senior management has voting rights with respect to our ordinary shares that are different from any other holder of our ordinary shares.

ITEM 7. MAJOR SHAREHOLDERS AND RELATED PARTY TRANSACTIONS

A. Major Shareholders

The following table sets forth information with respect to beneficial ownership of our ordinary shares as of the date of this annual report by:

- each of our directors and executive officers;
- our directors and executive officers as a group; and
- each person known to us to beneficially own 5% and more of our ordinary shares.

Beneficial ownership is determined in accordance with the rules and regulations of the SEC and includes the power to direct the voting or the disposition of the securities or to receive the economic benefit of the ownership of the securities. In computing the number of shares beneficially owned by a person and the percentage ownership of that person, we have included shares that the person has the right to acquire within 60 days of this annual report, including through the exercise of any option or other right and the vesting of restricted shares. These shares, however, are not included in the computation of the percentage ownership of any other person. The calculations of percentage ownership in the table below is based on 100,217,260 ordinary shares outstanding as of the date of this annual report.

Name	Ordinary Shares Beneficially Owned	Percentage
Directors and Officers		
Daniel Villalba	60,000	*
Santiago Seage	20,000	*
Jack Robinson	5,690	*
All Directors and executive officers as group	85,690	*
5% Beneficial Owners		
ACIL Luxco 2 S.A. (1)	41,557,663	41.47%

Note:—

(1) This information is based solely on the Schedule 13D filed on April 7, 2017 by Abengoa, S.A., a corporation incorporated under the laws of Spain. The direct beneficial owner of the shares is ACIL Luxco 2 S.A. The registered address of Abengoa, S.A. is Campus Palmas Altas, C/ Energia Solar, 41014, Seville, Spain. Once the Share Sale is complete, for which all conditions precedent have been satisfied and for which the parties have commenced the process for the transfer of our shares, which we expect to close in the upcoming days, Alqonquin will own 25,000,000 shares, or approximately 25.0% of our outstanding shares and ACIL Luxco 2 S.A. will own 6,844,547 shares, or approximately 16.47% of our outstanding shares.

We have one class of ordinary shares, and each holder of our ordinary shares is entitled to one vote per share.

As of the date of this annual report, 100,217,260 of our ordinary shares were outstanding. Because some of our ordinary shares are held by brokers and other nominees, the number of shares held by and the number of beneficial holders with addresses in the United States is not fully ascertainable. As of the date of this annual report, to the best of our knowledge, one of our shareholders of record was located in the United States and held in the aggregate 100,217,259 ordinary shares representing approximately 99.99% of our outstanding shares. However, the United States shareholders of record include Cede & Co., which, as nominee for The Depositary Trust Company, is the record holder of all such ordinary shares. Accordingly, we believe that the shares held by Cede & Co. include ordinary shares beneficially owned by both United States and non-United States beneficial owners. As a result, these numbers may not accurately represent the number of beneficial owners in the United States.

Arrangements for Change in Control of the Company

Based on the Schedule 13D filed by Abengoa on April 7, 2017 Abengoa Concessions Investments Limited, an indirect subsidiary of Abengoa, S.A., has pledged our ordinary shares, representing approximately 41.47% of our outstanding shares, as collateral under their New Money 1 Tradable Notes and loans. If Abengoa defaults on these financing arrangements, such lenders may foreclose on, and dispose of, the pledged shares and the resulting change in beneficial ownership of such shares would result in a change in control of us. Once the Share Sale is complete, for which all conditions precedent have been satisfied and for which the parties have commenced the process for the transfer of our shares, which we expect to close in the upcoming days, Algonquin will own 25,000,000 shares, or approximately 25.0% of our outstanding shares.

B. Related Party Transactions

Most of our assets have an operation and maintenance agreement with Abengoa entities. We also have engineering, procurement and construction agreements with Abengoa entities, and in Peru and South Africa, service agreements that provide administrative support.

Additionally, we entered into the Abengoa ROFO Agreement and Financial Support Agreement with Abengoa.

Operation and Maintenance Contracts at project-level

Each of our project-level companies have entered into an operation and maintenance agreement with an Abengoa subsidiary, with the exception of ACT, Palmucho, Quadra 1, Quadra 2 and Seville PV, where the contract is with third-party providers and Mini-hydro Peru where we provide the operation and maintenance services.

- ***Term***. Contract terms range from 20 to 30 years, typically mirroring the duration of financing contracts. The only exceptions are ATN, ATS, ATN2, Solaben 2/3 and Solacor 1/2 which are subject to shorter terms, with renewal clauses.

- ***Services***. Contracts *typically* cover all day-to-day operation and maintenance services, including procurement of equipment, scheduling and performance of maintenance, operation of the facility, training and supervision of personnel, as well as compliance with laws and regulations, safety and security programs, environmental services and technical reporting.

- ***Termination***. Typically, either party may terminate the agreement upon default by the counterparty. The relevant project-level company that owns the asset can typically terminate due to payment default, winding-up of the operator, failure of the operator to perform material obligations, termination of the PPA and, in some cases, for failure to reach certain performance ratios, the imposition of fines or penalties in excess of certain threshold amounts or force majeure. The operator can typically terminate in the event of payment default, winding-up of the project-level company, failure of the project-level company to perform material obligations and, in some cases, force majeure. Some projects allow termination by us at certain points in time.

- ***Compensation***. Operation and maintenance contracts in Solana and Mojave provide for a fixed fee of approximately $500,000 per plant per year, which is indexed to U.S. CPI and a variable fee paid in periods in which net operating profit exceeds the target. In addition, the operator is entitled to reimbursement of certain costs. In other projects, including ATN, ATS and each of our solar power assets in Spain, the operation and maintenance contract provides for an all-in fee under which the operator must bear substantially all costs for the operation and maintenance of the plant.

Local Services Agreements in South Africa and Peru

After replacing Abengoa with our own local services employees in most of our assets, we maintain local services agreements with a local Abengoa subsidiary only in South Africa for Kaxu and in Peru for ATN, ATS and ATN2. These agreements include renewal clauses that allow termination from one year to another or upon a short time notice. The overall compensation amounts to approximately $1.2 million per year.

Engineering, Procurement and Construction Agreements at project level

Each of our project-level companies entered into an EPC contract with a local Abengoa subsidiary. These contracts typically provide for the construction of the asset and are in place until the asset reaches COD or production guarantees are met or paid. EPC contracts may contain warranties such as those against defects in design, materials and workmanship after completion of the asset and may also provide a performance guarantee.

Abengoa Right of First Offer

Pursuant to the Abengoa ROFO Agreement, which we and Abengoa entered into on June 13, 2014, as amended and restated on December 9, 2014, Abengoa and its affiliates granted us and our affiliates a right of first offer on any proposed sale, transfer or other disposition of any of their contracted renewable energy, efficient natural gas power, electric transmission or water assets that are in operation and any other renewable energy, efficient natural gas power, electric transmission and water asset that is expected to generate contracted revenue and that Abengoa has transferred to an investment vehicle that are located in our primary geographies: (i) North America (the United States, Canada and Mexico); (ii) the following countries in South America: Chile, Peru, Uruguay, Brazil and Colombia; and (iii) the European Union. In addition, with respect to selected countries in Africa, the Middle East and Asia, which we refer to as our secondary geographies, we agreed to four assets that are also considered within the scope of the Abengoa ROFO Agreement.

Whenever we acquire an asset from Abengoa in the secondary geographies, or, if after 60 days of negotiations we and Abengoa are unable to reach an agreement on an asset offered for sale to us, we will update the list to include a replacement asset. If we and Abengoa are unable to agree on the replacement asset, Abengoa will propose three additional assets in the secondary geographies and we will select one to replace the asset removed from the list. Thereafter, the selected asset will also be considered an asset under the Abengoa ROFO Agreement. This right of first offer will not apply to a merger with or into, or sale of a high percentage of Abengoa's assets to, an unaffiliated third party, or to an internal restructuring.

If Abengoa transfers interests in any asset under the Abengoa ROFO Agreement to any affiliate or to an investment vehicle, then Abengoa must obtain an accession agreement from such transferee subjecting the transferred asset under the Abengoa ROFO Agreement to our right of first offer. For purposes of this requirement, “investment vehicle” means any person (A) (i) formed by Abengoa to act as an investment vehicle or (ii) that is an affiliate of Abengoa that Abengoa intends to use as an investment vehicle or becomes an investment vehicle due to an investment by a third party and (B) with the purpose of providing equity to projects related to any renewable energy, efficient natural gas power, electric transmission line and water contracted revenue assets that are to be, are being or were previously developed, sponsored, initiated or launched by Abengoa or any of its affiliates, irrespective of the amount of equity invested in such person by Abengoa or any such affiliate. Abengoa Project Warehouse 1 qualifies as an “investment vehicle” and has agreed to be subject to the Abengoa ROFO Agreement.

In addition, we have a “negotiation call” right under which we can require Abengoa to negotiate in good faith for the sale to us of any asset under the Abengoa ROFO Agreement that has been in operation for 18 months.

The Abengoa ROFO Agreement has an initial term of five years from the consummation of our IPO. We will be able to unilaterally extend the term of the Abengoa ROFO Agreement as many times as desired for an additional three-year period; provided that we have executed at least one acquisition in the previous two years after having been offered at least four projects.

Prior to engaging in any negotiation regarding any disposition, sale or other transfer of any asset under the Abengoa ROFO Agreement, Abengoa will deliver a written notice to us thereof, including a preliminary set of information that is relevant for us to make a determination regarding the asset under the Abengoa ROFO Agreement including the price at which Abengoa proposes to sell it to us. Once that information is received and if we do not notify Abengoa within 10 days that the information is insufficient, a 60-day negotiation period will start. If an agreement is not reached, Abengoa may, during the following 30 months, only sell, transfer, dispose or recontract such asset under the Abengoa ROFO Agreement to a third party (or to agree in writing to undertake such transaction with a third party) on terms and conditions generally no less favorable to Abengoa than those offered by Abengoa to us. If an asset that was already the subject of negotiations is presented again, we will have a 15-day period to negotiate. After such 30-month period, the asset will cease to be an asset under the Abengoa ROFO Agreement.

We will pay to Abengoa a fee of 1% of the equity purchase price of any asset under the Abengoa ROFO Agreement that we acquire as consideration for Abengoa granting us the right of first offer.

Under the Abengoa ROFO Agreement, Abengoa is not obligated to sell any asset under the Abengoa ROFO Agreement and, therefore, we do not know when, if ever, these assets will be offered to us. In addition, in some of the assets offered to us under the Abengoa ROFO Agreement, Abengoa may have equity partners with rights regulating divestitures by Abengoa of its stake such as drag-along and tag-along clauses, and rights of first refusal, among others. We will consider and take into account all these clauses when deciding whether to present an offer.

Abengoa may offer to sell to us contracted assets in business sectors or geographic regions not covered by the Abengoa ROFO Agreement, even though we do not have a ROFO over them as described in this section. We will evaluate these opportunities on a case-by-case basis.

Any transaction between Abengoa and us (including the proposed acquisition of any asset under the Abengoa ROFO Agreement) will be subject to our related party transaction policy, which will require prior approval of such transaction by a majority of the non-conflicted directors of our board of directors who would normally be independent as of the date hereof. See “Item 7.B—Related Party Transactions—Procedures for Review, Approval and Ratification of Related Party Transactions; Conflicts of Interest,” “Item 3.D—Risk Factors—Risks Related to Our Relationship with Abengoa—We may not be able to consummate future acquisitions from AAGES, Algonquin or Abengoa” and “Item 3.D—Risk Factors.”

Abengoa may enter into agreements with other companies with the objective of jointly financing the construction of new projects consisting of concessional assets which are included in Abengoa’s current or future portfolio. Pursuant to the terms of the Abengoa ROFO Agreement, we expect that any investing vehicle created by Abengoa and a potential partner with this purpose will sign the Abengoa ROFO Agreement in the same terms of Abengoa.

Financial Support Agreement

We and Abengoa entered into a Financial Support Agreement on June 13, 2014, which was amended and restated September 28, 2017, for a period of five years, pursuant to which Abengoa will maintain any guarantees (whether Abengoa guarantees, bank guarantees, technical guarantees or otherwise) or letters of credit currently outstanding in our or any of our affiliates' favor for a period of up to five years from the date of our IPO.

In July 2017, following our obligation to periodically review the possible substitution of such guarantees, we issued financial guarantees amounting to $112 million in favor of the off-takers of some of our projects, which were previously issued by Abengoa under the Financial Support Agreement. At the same time, Abengoa signed an agreement committing to maintain the rest of guarantees until June 2019.

AAGES Right of First Offer

Pursuant to the AAGES ROFO Agreement, which we and AAGES entered into on March 5, 2018 and that will become effective upon completion of the Share Sale, for which all conditions precedent have been satisfied and for which the parties have commenced the process for the transfer of our shares which we expect to close in the upcoming days, AAGES granted us a right of first offer on any proposed sale, transfer or other disposition of the AAGES' ROFO Assets.

If AAGES transfers interests in any AAGES ROFO Asset, then AAGES must require such transferee to acquire the AAGES ROFO Asset subject to our right of first offer except under certain circumstances summarized below. The AAGES ROFO Agreement has an initial term of ten years.

Prior to engaging in any negotiation regarding any disposition, sale or other transfer of any asset, AAGES will deliver a written notice to us thereof, including a predefined set of information that is relevant for us to make a determination regarding the AAGES ROFO Asset, including the indicative price at which AAGES proposes to sell it to us. Once that information is received, a 60-day negotiation period will start. If an agreement is not reached, AAGES, during the following 30 months, may only sell, transfer, dispose or recontract such asset to a third party for an aggregate purchase price that is not less than 105% of the last purchase price we offered during the negotiation period for assets located outside Canada and the US. For U.S. or Canadian assets, the purchase price must not be less than 100% of the last purchase price we offered during the negotiation period.

Under the AAGES ROFO Agreement, AAGES is not obligated to sell any asset and, therefore, we do not know when, if ever, these assets will be offered to us. In addition, in some of the assets under the AAGES ROFO Agreement, AAGES may have equity partners with rights regulating divestitures by AAGES of its stake such as drag-along and tag-along clauses, and rights of first refusal, among others. We will consider and take into account all these clauses when deciding whether to present an offer.

Any material transaction between AAGES and us (including the proposed acquisition of any AAGES ROFO Asset) will be subject to our related party transaction policy, which will require prior approval of such transaction by a majority of the non-conflicted directors of our board of directors. See "Item 7.B—Related Party Transactions—Related Party Transaction Policy; Conflicts of Interest," "Item 3.D—Risk Factors—Risks Related to Our Relationship with Abengoa—We may not be able to consummate future acquisitions from AAGES, Algonquin or Abengoa" and "Item 3.D—Risk Factors."

AAGES may enter into agreements with other companies with the objective of jointly developing the construction of new projects consisting of concessional assets which are included in AAGES' current or future portfolio. Pursuant to the terms of the AAGES ROFO Agreement, AAGES may sell equity in these assets to third parties without being subject to the AAGES ROFO Agreement under certain circumstances in order to enhance the likelihood of success or financial prospects of such asset.

AAGES Shareholders Agreement

In connection with the acquisition of 25.0% of our ordinary shares by Algonquin (indirectly through a subsidiary of AAGES), for which all conditions precedent have been satisfied and for which the parties have commenced the process for the transfer of our shares, which we expect to close in the upcoming days, we entered into a Shareholders Agreement with Algonquin and AAGES, which will become effective upon completion of the Share Sale. The Shareholders Agreement, among other things, sets forth certain rights and restrictions with respect to our ordinary shares, the main terms of which are summarized below.

Director Appointment Rights

The Shareholders Agreement provides that, if and to the extent provided in our articles, AAGES or Algonquin will have the right to appoint to our board the maximum number of directors that corresponds to AAGES' and Algonquin's holding of voting rights, as per articles of association but in any event no more than (i) such number of directors as corresponds to 41.5% of our voting securities; and (ii) 50% of our board less one, and if the resulting number is not a whole number, it shall be rounded up to the next whole number.

One of the directors appointed by AAGES and Algonquin holding in the aggregate at least 25.0% of our voting securities will have the right to be elected to any committee of our directors (except for the audit committee and related party transaction committee, and in those in which they are conflicted, or it is against the applicable law). In addition, so long as AAGES and Algonquin have the right to appoint a director and no such director is then serving on our board of directors, AAGES and Algonquin may appoint an observer to our board of directors and any committee thereof (except for the audit committee and related party transaction committee, and in those in which they are conflicted, or it is against the applicable law). Until the Share Sale is complete, neither AAGES nor Algonquin will be permitted to appoint any members to our board of directors.

Dividends Distribution

We agreed that AAGES and Algonquin may terminate the Shareholders Agreement with respect to itself and its affiliates if, among others, our board of directors confirms a dividend payment objective that is lower than 80% of the cash available for distribution or our board of directors does not confirm any dividend payment objective at least once during any period of more than 14 consecutive months.

Pre-emption rights

AAGES and Algonquin may subscribe in cash for (i) up to 100% of our ordinary shares if the purpose of the issuance is to fund our acquisition of assets under the AAGES ROFO Agreement and Algonquin ROFO Agreement; and (ii) up to 66% of our ordinary shares if the purpose of the issuance is to fund our acquisition of assets under the Abengoa ROFO Agreement. If we issue ordinary shares for any other purpose, AAGES and Algonquin may subscribe in cash for ordinary shares in the amount pro rata to such AAGES' and Algonquin's aggregate holding of voting rights.

In addition, if AAGES and Algonquin elect to subscribe for at least 50% of an offering of our ordinary shares that will be listed, the price per ordinary share for all persons that participate in such offering will be equal to 97% of the USD volume-weighted average closing price per ordinary share on NASDAQ (or other applicable stock exchange) over the 20 trading days immediately preceding the date of AAGES' and Algonquin's receipt of notice of such proposed offering from us.

AAGES'/Algonquin's Initial Funding Commitment

Subject to the approval of the board of directors of Algonquin, AAGES and Algonquin agreed to provide equity funding as required by us for the acquisition of assets and/or interests by us or our subsidiaries during 2018 and 2019, but no higher than $100 million.

Standstill

Algonquin will not acquire any of our voting securities which may result in AAGES and Algonquin holding in the aggregate more than 41.5% of the total voting rights. However, AAGES and Algonquin will not be in breach of this clause if it is a result of: (i) the acquisition of shares (or voting rights attached to such shares) by AAGES and Algonquin from Abengoa under the option agreement between Abengoa and Algonquin for the remaining 16.47% stake in us, subject to approval by the DOE, and (ii) the exercise of subscription rights as part of the Initial Funding Commitment described above. In such case, until AAGES' and Algonquin's holding is again equal to or below 41.5%, AAGES and Algonquin cannot acquire any additional voting securities of us. The Shareholders Agreement further provides that in any case AAGES and Algonquin cannot acquire 46.0% or more of our voting securities or otherwise acquire control over us.

Also, AAGES and Algonquin will not be in breach of the standstill restriction if the shareholding of AAGES and Algonquin has increased in connection with our action to reduce the number of our outstanding shares.

Termination

The Shareholders Agreement will terminate if, among others, AAGES and Algonquin and/or their affiliates cease to hold in the aggregate at least 10% of the total voting rights attached to our voting securities. In addition, Shareholders Agreement could terminate if, among others, the (i) our articles are amended in a manner that adversely affects the rights of AAGES and Algonquin to appoint directors, as such rights exist under our articles as of the date of the Shareholders Agreement; or (ii) we give notice to AAGES and Algonquin if: (a)(with respect to Algonquin and its affiliates only) a change of control over Algonquin occurs; or (b)(with certain exceptions) on three occasions AAGES and Algonquin have not subscribed for our ordinary shares in the amount of at least its pro rata share, or have not fully paid for subscribed ordinary shares; or (c)(with respect to Algonquin only) if the Algonquin ROFO Agreement terminates other than in connection with its breach by us.

Algonquin drop down agreement and Right of First Offer on assets outside the United States or Canada

Under the Algonquin ROFO Agreement, Algonquin agreed to periodically discuss with us the possibility of offering for sale interests in certain assets owned by Algonquin companies in Canada or the United States.

Pursuant to the Algonquin ROFO Agreement, which we and Algonquin entered into on March 5, 2018 and that will become effective upon completion of the Share Sale, for which all conditions precedent have been satisfied and for which the parties have commenced the process for the transfer of our shares, which we expect to close in the upcoming days, Algonquin granted us a right of first offer on any proposed sale, transfer or other disposition of any of their contracted facilities or infrastructure facilities located outside of the United States or Canada which are developed under expected long-term revenue agreements or concession agreements.

If Algonquin transfers interests in any asset under the Algonquin ROFO Agreement, then Algonquin must require such transferee to acquire any asset under the Algonquin ROFO Agreement subject to our right of first offer except under certain circumstances summarized below. The Algonquin ROFO Agreement has an initial term of ten years.

Prior to engaging in any negotiation regarding any disposition, sale or other transfer of any asset under the Algonquin ROFO Agreement, Algonquin will deliver a written notice to us thereof, including a set of predefined information that is relevant for us to make a determination regarding any asset under the Algonquin ROFO Agreement, including the indicative price at which Algonquin proposes to sell it to us. Once that information is received, a 60-day negotiation period will start. If an agreement is not reached, Algonquin, during the following 30 months, may only sell, transfer, dispose or recontract such asset under the Algonquin ROFO Agreement to a third party for an aggregate purchase price that is not less than 105% of the last purchaser price we offered during the negotiation period.

Under the Algonquin ROFO Agreement, Algonquin is not obligated to sell any assets under the Algonquin ROFO Agreement and, therefore, we do not know when, if ever, these assets will be offered to us. In addition, in some of the assets under the Algonquin ROFO Agreement, Algonquin may have equity partners with rights regulating divestitures by Algonquin of its stake such as drag-along and tag-along clauses, and rights of first refusal, among others. We will consider and take into account all these clauses when deciding whether to present an offer.

Any material transaction between Algonquin and us (including the proposed acquisition of any asset under the Algonquin ROFO Agreement) will be subject to our related party transaction policy, which will require prior approval of such transaction by a majority non-conflicted directors of our board of directors. See “Item 7.B—Related Party Transactions—Related Party Transactions Policy; Conflicts of Interest,” “Item 3.D—Risk Factors—Risks Related to Our Relationship with Abengoa—We may not be able to consummate future acquisitions from AAGES, Algonquin or Abengoa” and “Item 3.D—Risk Factors.” In addition, Algonquin may terminate the Algonquin ROFO agreement with us with a 180-day notice.

Procedures for Review, Approval and Ratification of Related Party Transactions; Conflicts of Interest

Our policy for the review, approval and ratification of related party transactions was updated and approved by the board of directors on February 28, 2018. Our policy requires that all transactions with related parties are subject to approval or ratification in accordance with the procedures set forth in the policy by the non-conflicted directors at the board of directors. With respect of any transaction with AAGES, Algonquin, Abengoa or its affiliates (other than our subsidiaries), including transactions pursuant to the ROFO Agreements, the Related Party Transaction Committee is required to review all of the relevant facts and circumstances and report its conclusions to the board. A majority of non-conflicted directors are required to either approve or disapprove of the entry into the transaction. In determining whether to approve or ratify a transaction with AAGES, Algonquin or Abengoa, the directors unaffiliated with such entity are to consider, among other factors they may deem appropriate, whether the transaction is on terms no less favorable than terms generally available to an unaffiliated third-party under the same or similar circumstances and the extent of AAGES', Algonquin's or Abengoa's interest in the transaction. Our Related Party Transaction Policy is available on our website at www.atlanticayield.com.

Code of Conduct

We have adopted a code of conduct applicable all directors, officers and employees of Atlantica Yield and our subsidiaries. The Code of Conduct is available on our website at www.atlanticayield.com, is communicated to all employees and is reviewed at least annually.

C. Interests of Experts and Counsel

Not applicable.

ITEM 8. FINANCIAL INFORMATION

A. Consolidated Statements and Other Financial Information.

We have included the Annual Consolidated Financial Statements as part of this annual report. See "Item 18—Financial Statements."

Dividend Policy

Our Cash Dividend Policy

We expect to pay a quarterly dividend on or about the 75th day following the expiration of the first, second and third fiscal quarters to our shareholders of record on or about the 60th day following the last day of such fiscal quarters. A quarterly dividend corresponding to the fourth quarter is usually declared in the first quarter of the following year. We expect to pay this dividend on or about the 82nd day following the expiration of the corresponding fourth fiscal quarter to our shareholders of record in general on or about the 72nd day following the last day of such fiscal quarter. However, there might be exceptions to these dates. Additionally, our board of directors may change our dividend policy at any point in time or modify the dividend for specific quarters following prevailing conditions.

We declared our first quarterly dividend in November 2014 and paid it on December 15, 2014. Since then, we declared and paid quarterly dividends in 2014 and 2015. On November 5, 2015, our board of directors approved a quarterly dividend corresponding to the third quarter of 2015. The dividend was paid on December 16, 2015, to shareholders of record as of November 30, 2015, and from that amount we retained $9 million of the dividend attributable to Abengoa in accordance with the provisions of the parent support agreement. See "Item 4.B—Business Overview—Electric Transmission—Exchangeable Preferred Equity Investment in Abengoa Concessões Brasil Holding."

In February 2016, taking into consideration the uncertainties resulting from the situation of Abengoa, the board of directors decided to postpone the decision whether to declare a dividend in respect of the fourth quarter of 2015 until the second quarter of 2016. In May 2016, considering the uncertainties that remained in Abengoa's situation, our board of directors decided not to declare a dividend in respect of the fourth quarter of 2015 and to postpone the decision on whether to declare a dividend in respect of the first quarter 2016 until we had obtained greater clarity on cross default and change of ownership issues. On August 3, 2016, the board of directors decided to declare a dividend of $0.145 per share for the first quarter of 2016 and a dividend of $0.145 per share for the second quarter of 2016. The dividend was paid on September 15, 2016, to shareholders of record August 31, 2016. From that amount, we retained $12.3 million of the dividend attributable to Abengoa. On November 11, 2016, our board of directors, based on waivers or forbearances obtained to that date, decided to declare a dividend of $0.163 per share, which was paid on December 15, 2016, to shareholders of record on November 30, 2016. From that amount, we retained $6.7 million of the dividend attributable to Abengoa.

On February 27, 2017, the board of directors declared a dividend of $0.25 per share corresponding to the fourth quarter of 2016, which was paid on March 15, 2017. From that amount, we retained $10.4 million of the dividend attributable to Abengoa. On May 15, 2017, the board of directors declared a dividend of $0.25 per share corresponding to the first quarter of 2017, which was paid on June 15, 2017. On August 3, 2017, the board of directors declared a dividend of $0.26 per share corresponding to the second quarter of 2017, which was paid on September 15, 2017. On November 10, 2017, our board of directors approved a dividend of $0.29 per share, which was paid on December 15, 2017. On February 27, 2018, our board of directors approved a dividend of 0.31 per share which is expected to be paid on or about March 22, 2018.

We intend to distribute a significant portion of our cash available for distribution as dividend, after considering the cash available for distribution that we expect our projects will be able to generate, less reserves for the prudent conduct of our business (including for, among other things, dividend shortfalls as a result of fluctuations in our cash flows). Our target payout ratio is 80% of the cash available for distribution, on an annual basis. We intend to distribute a quarterly dividend to shareholders. Our board of directors may, by resolution, amend the cash dividend policy at any time. We intend to grow our business via improvements in our existing projects and through the acquisition of operational projects when market conditions are favorable, which, we believe, will facilitate the growth of our cash available for distribution and enable us to increase our dividend per share over time. However, the determination of the amount of cash dividends to be paid to holders of our shares will be made by our board of directors and will depend upon our financial condition, results of operations, cash flow, long-term prospects and any other matters that our board of directors deem relevant.

Our cash available for distribution is likely to fluctuate from quarter to quarter, in some cases significantly, as a result of the seasonality of our assets, the terms of our financing arrangements, maintenance and outage schedules, among other factors. Accordingly, during quarters in which our projects generate cash available for distribution in excess of the amount necessary for us to pay our stated quarterly dividend, we may reserve a portion of the excess to fund cash distributions in future quarters. In quarters in which we do not generate sufficient cash available for distribution to fund our stated quarterly cash dividend, if our board of directors so determines, we may use retained cash flow from other quarters, as well as other sources of cash, to pay dividends to our shareholders.

Risks Regarding Our Cash Dividend Policy

We do not have a significant operating history as an independent company upon which to rely in evaluating whether we will have sufficient cash available for distribution and other sources of liquidity to allow us to pay dividends on our shares at our initial quarterly dividend level on an annualized basis or at all. There is no guarantee that we will pay quarterly cash dividends to our shareholders. We do not have a legal obligation to pay our initial quarterly dividend or any other dividend. While we currently intend to grow our business and increase our dividend per share over time, our cash dividend policy is subject to all the risks inherent in our business and may be changed at any time as a result of certain restrictions and uncertainties, including the following:

- The amount of our quarterly cash available for distribution could be impacted by restrictions on cash distributions contained in our project-level financing arrangements, which require that our project-level subsidiaries comply with certain financial tests and covenants in order to make such cash distributions. Generally, these restrictions limit the frequency of permitted cash distributions to semi-annual or annual payments, and prohibit distributions unless specified debt service coverage ratios, historical and/or projected, are met. See the sub-sections entitled "—Project Level Financing" under the individual project descriptions in "Item 4.B—Business Overview—Our Operations." When forecasting cash available for distribution and dividend payments we have aimed to take these restrictions into consideration, but we cannot guarantee future dividends.

- The financing arrangements of some of our project subsidiaries contained cross-default provisions related to Abengoa, such that debt defaults by Abengoa could trigger defaults under such project financing arrangements. In addition, some of our project financing arrangements contained a change of control provision that would be triggered if Abengoa ceases to own at least 35.0% of Atlantica Yield's shares. During the years 2015, 2016 and 2017, waivers and forbearances were obtained for most of our project financing agreements from all the parties of these project financing arrangements containing such covenants. In March 2017, we obtained a waiver in our Kaxu project financing arrangement which waives any potential cross-defaults with Abengoa up to that date, but it does not cover potential future cross-default events. In the case of Solana and Mojave, a forbearance agreement signed with the DOE in 2016 with respect to these assets allows reductions of Abengoa's ownership of our shares if it results from (i) a sale or other disposition at any time pursuant to and in connection with a subsequent insolvency proceeding by Abengoa, or (ii) capital increases by us. In other events of reduction of ownership by Abengoa below the minimum ownership threshold such as sales of shares by Abengoa, the available DOE remedies will not include debt acceleration, but DOE remedies available could include limitations on distributions to us from Solana and Mojave. In addition, the minimum ownership threshold for Abengoa's ownership of our shares has been reduced from 35.0% to 30.0%. In November 2017, in the context of the agreement reached between Abengoa and Algonquin for the acquisition by Algonquin of 25.0% of our shares and based on the obligations of Abengoa under an EPC contract, we signed a consent in relation to the Solana and Mojave projects which reduces the minimum ownership required by Abengoa in us from 30.0% to 16.0%, subject to certain conditions precedent. In Solana, the EPC guarantee period expired without reaching the expected production. As the EPC supplier, Abengoa agreed to provide certain compensations. As a result, the main conditions precedent included several payments by Abengoa to Solana before December 2017 and February 2018 (subsequently postponed to May 2018), for a total amount of $120 million. Additionally, Abengoa has recognized other obligations to Solana for $6.5 million per half-year over 10 years starting in December 2018. In December 2017, Solana received $42.5 million which was used to repay project finance debt. Solana is expected to receive in March 2018 an additional $77.5 million. From this amount $52.5 million are expected to be used to repay project debt and $25 million are expected to cover other current and potential future Abengoa obligations.

- Additionally, indebtedness we have incurred under the 2019 Notes, the Revolving Credit Facility and the Note Issuance Facility contain, among other covenants, certain financial incurrence and maintenance covenants, as applicable. See "Item 5.B—Liquidity and Capital Resources—Financing Arrangements." In addition, we may incur debt in the future to acquire new projects, the terms of which will likely require commencement of commercial operations prior to our ability to receive cash distributions from such acquired projects. These agreements likely will contain financial tests and covenants that our subsidiaries must satisfy prior to making distributions. Should we or any of our project-level subsidiaries be unable to satisfy these covenants or if any of us are otherwise in default under such facilities, we may be unable to receive sufficient cash distributions to pay our stated quarterly cash dividends notwithstanding our stated cash dividend policy. See the "Project Level Financing" descriptions contained in "Item 4.B—Business Overview—Our Operations" for a description of such restrictions.

- We and our board of directors have the authority to establish cash reserves for the prudent conduct of our business and for future cash dividends to our shareholders, and the establishment of or increase in those reserves could result in a reduction in cash dividends from levels we currently anticipate pursuant to our stated cash dividend policy. These reserves may account for the fact that our project-level cash flows may vary from year to year based on, among other things, changes in prices under offtake agreements, operational costs and other project contracts, compliance with the terms of project debt including debt repayment schedules, the transition to market or recontracted pricing following the expiration of offtake agreements, working capital requirements and the operating performance of the assets. Our board of directors may increase reserves to account for the seasonality that has historically existed in our assets' cash flows and the variances in the pattern and frequency of distributions to us from our assets during the year. Furthermore, our board of directors may increase reserves in light of the uncertainty associated with Abengoa's financial condition to account for potential costs that we may incur or limitations that may be imposed upon us as a result of cross-defaults under our project financing arrangements associated with Abengoa.

- We may lack sufficient cash to pay dividends to our shareholders due to cash flow shortfalls attributable to a number of operational, commercial or other factors, including low availability, unexpected operating interruptions, legal liabilities, costs associated with governmental regulation, changes in governmental subsidies, changes in regulation, as well as increases in our operating and/or general and administrative expenses, including existing contracts with Abengoa and its subsidiaries, principal and interest payments on our and our subsidiaries' outstanding debt, income tax expenses, failure of Abengoa to comply with its obligations under the agreements in place including obligations of Abengoa as EPC contractor on assets that are still within their respective guarantee periods, working capital requirements or anticipated cash needs at our project-level subsidiaries. See "Item 3.D—Risk Factors" for more information on the risks to which our business is subject.

- We may pay cash to our shareholders via capital reduction in lieu of dividends in some years.

- Our project companies' cash distributions to us (in the form of dividends or other forms of cash distributions such as shareholder loan repayments) and, as a result, our ability to pay or grow our dividends, are dependent upon the performance of our subsidiaries and their ability to distribute cash to us. The ability of our project-level subsidiaries to make cash distributions to us may be restricted by, among other things, the provisions of existing and future indebtedness, applicable corporation laws and other laws and regulations.

- Our board of directors may, by resolution, amend the cash dividend policy at any time. Our board of directors may elect to change the amount of dividends, suspend any dividend or decide to pay no dividends even if there is ample cash available for distribution.

Our Ability to Grow our Business and Dividend

We intend to grow our business primarily through the improvement of existing assets and the acquisition of contracted power generation assets, electric transmission lines and other infrastructure assets, which, we believe will facilitate the growth of our cash available for distribution and enable us to increase our dividend per share over time. Our policy is to distribute a significant portion of our cash available for distribution as a dividend. However, the final determination of the amount of cash dividends to be paid to our shareholders will be made by our board of directors and will depend upon our financial condition, results of operations, cash flow, long-term prospects and any other matters that our board of directors deems relevant.

We expect that we will rely primarily upon external financing sources, including commercial bank borrowings and issuances of debt and equity securities, to fund any future growth capital expenditures. To the extent we are unable to finance growth externally, our cash dividend policy could significantly impair our ability to grow because we do not currently intend to reserve a substantial amount of cash generated from operations to fund growth opportunities. If external financing is not available to us on acceptable terms, our board of directors may decide to finance acquisitions with cash from operations, which would reduce or even eliminate our cash available for distribution and, in turn, impair our ability to pay dividends to our shareholders. To the extent we issue additional shares to fund growth capital expenditures, the payment of dividends on those additional shares may increase the risk that we will be unable to maintain or increase our per share dividend level. Additionally, the incurrence of additional commercial bank borrowings or other debt to finance our growth would result in increased interest expense, which in turn may impact our cash available for distribution and, in turn, our ability to pay dividends to our shareholders.

B. Significant Changes

There have been no significant changes since the date of the Annual Consolidated Financial Statements included in this annual report.

ITEM 9. THE OFFER AND LISTING

A. Offering and Listing Details.

Our ordinary shares trade on the NASDAQ Global Select Market under the symbol "AY." The following table sets forth, for the periods indicated, the high and low intraday sales price per ordinary share as reported by the NASDAQ Global Select Market since the date of our IPO.

	Price per Share	
	High	**Low**
	(Amounts in U.S. dollars)	
Most recent six months		
March 2018 (through March 6, 2018)	20.43	19.99
February 2018	25.53	19.44
January 2018	21.79	20.73
December 2017	22.58	20.62
November 2017	25.99	22.31
October 2017	22.55	19.30
September 2017	21.09	19.44
Year ended December 31, 2017		
Fourth quarter	25.99	19.30
Third quarter	22.66	19.44
Second quarter	21.77	19.38
First quarter	22.87	19.24
Year ended December 31, 2016		
Fourth quarter	19.80	16.55
Third quarter	21.32	18.01
Second quarter	19.17	15.78
First quarter	19.19	13.11
Most Recent Full Financial Years		
2017	25.99	19.44
2016	21.32	13.11
2015[1]	38.80	14.15

Note:—

(1) Our ordinary shares were admitted to trading on the NASDAQ Global Select Market following the consummation of our IPO on June 12, 2014. There was no public market for our ordinary shares before our IPO.

B. Plan of Distribution

Not applicable.

C. Markets

Our ordinary shares are traded on the NASDAQ Global Select Market under the symbol “AY.”

D. Selling Shareholders

Not applicable.

E. Dilution

Not applicable.

F. Expenses of the Issue

Not applicable.

ITEM 10. ADDITIONAL INFORMATION

A. Share Capital

Not applicable.

B. Memorandum and Articles of Association

The information called for by this item has been reported previously in our Registration Statement on Form 6-K (File No. 001-36487), filed with the SEC on May 26, 2016 as exhibit 3.1 and is incorporated by reference into this annual report.

C. Material Contracts

See “Item 4.B—Business Overview,” “Item 5.B—Liquidity and Capital Resources—Financing Arrangements” and “Item 7.B—Related Party Transactions.”

D. Exchange Controls

See “Item 5.A—Operating Results—Factors Affecting Our Results of Operations—Regulation.”

E. Taxation

Material UK Tax Considerations

The following is a general summary of material UK tax considerations relating to the ownership and disposal of our shares. The comments set out below are based on current UK tax law as applied in England and Wales and HM Revenue & Customs, or HMRC, practice (which may not be binding on HMRC) as at the date of this summary, both of which are subject to change, possibly with retrospective effect. They are intended as a general guide and apply to you only if you are a “U.S. Holder” (as defined in the section below entitled “Material U.S. Federal Income Tax Considerations”) and if:

- you hold Atlantica Yield shares as an investment for tax purposes, as capital assets and you are the absolute beneficial owner thereof for UK tax purposes;

- you are an individual, you are not resident in the United Kingdom for UK tax purposes and do not hold Atlantica Yield shares for the purposes of a trade, profession, or vocation that you carry on in the United Kingdom through a branch or agency, or if you are a corporation, you are not resident in the UK for UK tax purposes and do not hold the securities for the purpose of a trade carried on in the United Kingdom through a permanent establishment in the United Kingdom; and

- you are not domiciled in the United Kingdom for UK inheritance tax purposes.

This summary does not address all possible tax consequences relating to an investment in the shares. Certain categories of shareholders, including those falling outside the category described above, those carrying on certain financial activities, those subject to specific tax regimes or benefitting from certain reliefs or exemptions, those connected with us and those for whom the shares are employment-related securities may be subject to special rules and this summary does not apply to such shareholders and any general statements made in this disclosure do not take them into account.

This summary is for general information only and is not intended to be, nor should it be considered to be, legal or tax advice to any particular investor. It does not address all of the tax considerations that may be relevant to specific investors in light of their particular circumstances or to investors subject to special treatment under UK tax law.

Potential investors should satisfy themselves prior to investing as to the overall tax consequences, including, specifically, the consequences under UK tax law and HMRC practice of the acquisition, ownership and disposal of the shares in their own particular circumstances by consulting their own tax advisors.

UK Taxation of Dividends

We will not be required to withhold amounts on account of UK tax at source when paying a dividend in respect of our shares to a U.S. Holder.

U.S. Holders who hold their shares as an investment and not in connection with any trade carried on by them will not be subject to United Kingdom tax in respect of any dividends.

UK Taxation of Capital Gains

An individual holder who is a U.S. Holder will not be liable to UK capital gains tax on capital gains realized on the disposal of his or her Atlantica Yield shares unless such holder carries on (whether solely or in partnership) a trade, profession or vocation in the United Kingdom through a branch or agency in the United Kingdom to which the shares are attributable.

A corporate holder of shares that is a U.S. Holder will not be liable for UK corporation tax on chargeable gains realized on the disposal of its Atlantica Yield shares unless it carries on a trade in the United Kingdom through a permanent establishment to which the shares are attributable.

An individual holder of shares who is temporarily a non-UK resident for UK tax purposes will, in certain circumstances, become liable to UK tax on capital gains in respect of gains realized while he or she was not resident in the United Kingdom.

UK Inheritance Tax

Atlantica Yield shares which are registered on the main Atlantica Yield share register are assets situated in the United Kingdom for the purposes of UK inheritance tax. A gift of such assets by, or the death of, an individual holder of such assets may (subject to certain exemptions and reliefs) give rise to a liability to UK inheritance tax, even if the holder is neither domiciled in the United Kingdom nor deemed to be domiciled there (under certain rules relating to long residence or previous domicile). Generally, UK inheritance tax is not chargeable on gifts to individuals if the transfer is made more than seven complete years prior to death of the donor. For inheritance tax purposes, a transfer of assets at less than full market value may be treated as a gift and particular rules apply to gifts where the donor reserves or retains some benefit. Special rules also apply to close companies and to trustees of settlements who hold shares in Atlantica Yield bringing them within the charge to inheritance tax.

However, Atlantica Yield shares that are held by an individual whose domicile is determined to be the United States for the purposes of the United States-United Kingdom Double Taxation Convention relating to estate and gift taxes, or the U.S.-UK Estate Tax Treaty, and who is not for such purposes a national of the United Kingdom will not, provided any U.S. federal estate or gift tax chargeable has been paid, be subject to UK inheritance tax on the individual's death or on a lifetime transfer of the shares except in certain cases where the shares (i) are comprised in a settlement (unless, at the time the settlement was made, the settlor was domiciled in the United States and was not a national of the United Kingdom), (ii) are part of the business property of a UK permanent establishment or an enterprise, or (iii) pertain to a UK fixed base of an individual used for the performance of independent personal services. In such cases, the U.S.-UK Estate Tax Treaty generally provides a credit against U.S. federal tax liability for the amount of any tax paid in the United Kingdom in a case where the shares are subject both to UK inheritance tax and to U.S. federal estate or gift tax.

Stamp Duty and Stamp Duty Reserve Tax

The stamp duty and stamp duty reserve tax, or SDRT, treatment of the issue and transfer of, and the agreement to transfer, Atlantica Yield shares outside a depositary receipt system or a clearance service are discussed in the paragraphs under 'General' below. The stamp duty and SDRT treatment of such transactions in relation to such systems are discussed in the paragraphs under "Depositary Receipt Systems and Clearance Services" below.

General

No stamp duty, or SDRT, will arise on the issue of shares in registered form by Atlantica Yield.

An agreement to transfer our shares will normally give rise to a charge to SDRT at the rate of 0.5% of the amount or value of the consideration payable for the transfer. SDRT is, in general, payable by the purchaser.

Transfers of our shares will generally be subject to stamp duty at the rate of 0.5% of the consideration given for the transfer (rounded up to the next £5). The purchaser normally pays the stamp duty.

If a duly stamped transfer completing an agreement to transfer is produced within six years of the date on which the agreement is made (or, if the agreement is conditional, the date on which the agreement becomes unconditional) any SDRT already paid is generally repayable, normally with interest, and any SDRT charge yet to be paid is cancelled.

Depositary Receipt Systems and Clearance Services

Following the Court of Justice of the European Union's decision in C-569/07 HSBC Holdings Plc, Vidacos Nominees Limited v The Commissioners of Her Majesty's Revenue & Customs and the First-tier Tax Tribunal decision in HSBC Holdings Plc and The Bank of New York Mellon Corporation v. The Commissioners of Her Majesty's Revenue & Customs, Her Majesty's Revenue & Customs, or HMRC, has confirmed that 1.5% SDRT is no longer payable when new shares are issued to a clearance service or depositary receipt system.

Where our shares are transferred (i) to, or to a nominee or an agent for, a person whose business is or includes the provision of clearance services or (ii) to, or to a nominee or an agent for, a person whose business is or includes issuing depositary receipts, stamp duty or SDRT will generally be payable at the higher rate of 1.5% of the amount or value of the consideration given or, in certain circumstances, the value of the shares.

Except in relation to clearance services that have made an election under Section 97A(1) of the Finance Act of 1986 (to which the special rules outlined below apply), no stamp duty or SDRT is payable in respect of transfers or agreements to transfer within clearance services or depositary receipt systems. Accordingly, no stamp duty or SDRT should, in practice, be required to be paid in respect of transfers or agreements to transfer our shares within the facilities of the Depository Trust Company, or DTC.

There is an exception from the 1.5% charge on the transfer to, or to a nominee or agent for, a clearance service where the clearance service has made and maintained an election under section 97A(1) of the Finance Act 1986, which has been approved by HMRC. In these circumstances, SDRT at the rate of 0.5% of the amount or value of the consideration payable for the transfer will arise on any transfer of our shares into such an account and on subsequent agreements to transfer such shares within such account. It is our understanding that DTC has not made an election under section 97A(1) of the Finance Act of 1986.

Any liability for stamp duty or SDRT in respect of any other transfer into a clearance service or depositary receipt system, or in respect of a transfer within any clearance service or depositary receipt system, which does arise will strictly be accountable by the clearance service or depositary receipt system operator or their nominee, as the case may be, but will, in practice, be payable by the participants in the clearance service or depositary receipt system.

Material U.S. Federal Income Tax Considerations

The following is a summary of material U.S. federal income tax consequences of the acquisition, ownership and disposition of shares by U.S. Holders (as defined below). This summary is based upon U.S. federal income tax laws (including the IRC, final, temporary and proposed Treasury regulations, rulings, judicial decisions and administrative pronouncements) all as of the date hereof and all of which are subject to changes in wording or administrative or judicial interpretation occurring after the date hereof, possibly with retroactive effect.

As used herein, the term “U.S. Holder” means a beneficial owner of shares:

(a) that is, for U.S. federal income tax purposes, (i) a citizen or resident of the United States, (ii) a corporation (or other entity taxable as a corporation) created or organized in or under the laws of the United States or any political subdivision thereof, (iii) an estate the income of which is subject to U.S. federal income taxation regardless of its source, or (iv) a trust if a court within the United States is able to exercise primary supervision over the administration of the trust and one or more U.S. persons have the authority to control all substantial decisions of the trust, or the trust has validly elected to be treated as a domestic trust for U.S. federal income tax purposes;

(b) that holds the shares as capital assets for U.S. federal income tax purposes; and

(c) that owns, directly, indirectly or by attribution, less than 5% both of the vote and value of the interest in Atlantica Yield.

This summary does not cover all aspects of U.S. federal income taxation that may be relevant to, or the actual tax effect that any of the matters described herein will have on, the acquisition, ownership or disposition of shares by particular investors, and does not address state, local, foreign or other tax laws. This summary does not address all of the U.S. federal income tax considerations that may apply to U.S. Holders that are subject to special tax rules, such as U.S. citizens or lawful permanent residents of the United States living abroad, insurance companies, tax-exempt organizations, certain financial institutions, persons subject to the alternative minimum tax or the net investment income tax, dealers and certain traders in securities or currencies, persons holding shares as part of a straddle, hedging, conversion or other integrated transaction, partners in entities classified as partnerships for U.S. federal income tax purposes, persons holding shares through an individual retirement account or other tax-deferred account, persons whose functional currency is not the U.S. dollar or persons that carry on a trade, business or vocation in the United Kingdom through a branch, agency or permanent establishment to which the shares are attributable. Such U.S. holders may be subject to U.S. federal income tax consequences different from those set forth below.

If an entity classified as a partnership for U.S. federal income tax purposes holds shares, the U.S. federal income tax treatment of a partner in such an entity generally will depend upon the status of the partner and the activities of the partnership. An entity treated as a partnership for U.S. federal income tax purposes that holds shares and its partners are urged to consult their own tax advisors regarding the specific U.S. federal income tax consequences to the partnership and its partners of acquiring, owning and disposing of the shares.

This discussion assumes that Atlantica Yield is not, was not for its 2016 taxable year, and will not become a passive foreign investment company, or PFIC, for U.S. federal income tax purposes, as discussed below under "—Passive foreign investment company rules."

Potential investors in shares should consult their own tax advisors concerning the specific U.S. federal, state and local tax consequences of the ownership and disposition of shares in light of their particular situations as well as any consequences arising under the laws of any other taxing jurisdiction.

Taxation of distributions on the shares

Distributions received by a U.S. Holder on shares generally will constitute dividends to the extent paid out of Atlantica Yield current or accumulated earnings and profits (as determined for U.S. federal income tax purposes). Atlantica Yield intends to annually calculate its earnings and profits in accordance with U.S. federal income tax principles. If distributions exceed Atlantica Yield's current and accumulated earnings and profits, such excess distributions will constitute a non-taxable return of capital to the extent of the U.S. Holder's tax basis in its shares and will result in a reduction of such tax basis. To the extent such excess exceeds a U.S. Holder's tax basis in the shares, such excess will generally be taxed as capital gain.

Subject to certain exceptions for short-term and hedged positions, dividends received by certain non-corporate U.S. Holders of shares generally will be subject to U.S. federal income taxation at rates lower than those applicable to other ordinary income if the dividends are "qualified dividend income." Distributions received by a U.S. Holder on shares will be qualified dividend income if: (i) shares are readily tradable on an established securities market in the United States (such as NASDAQ Global Select Market, where our shares are listed) and (ii) Atlantica Yield was not, for the year prior to the year in which the dividends are paid, and is not, for the year in which the dividends are paid, a PFIC. As discussed below under "—Passive foreign investment company rules," although there can be no assurance that Atlantica Yield will not be considered a PFIC for any taxable year, Atlantica Yield does not believe that it was a PFIC for its 2017 taxable year and does not expect to be a PFIC for its current taxable year or in the foreseeable future. Non-corporate U.S. Holders should consult their own tax advisors to determine whether they are subject to any special rules that limit their ability to be taxed at these favorable rates. Corporate U.S. Holders will not be entitled to claim the dividends-received deduction with respect to dividends paid by Atlantica Yield. Dividends will be included in a U.S. Holder's income on the date of the U.S. Holder's receipt of the dividend.

Taxation upon sale or other disposition of shares

A U.S. Holder generally will recognize U.S. source capital gain or loss on the sale or other disposition of shares, which will generally be long-term capital gain or loss if the U.S. Holder has owned shares for more than one year. The amount of the U.S. Holder's gain or loss will be equal to the difference between such U.S. Holder's adjusted tax basis in the shares sold or otherwise disposed of and the amount realized on the sale or other disposition. Net long-term capital gain recognized by certain non-corporate U.S. Holders will be taxed at a lower rate than the rate applicable to ordinary income. The deductibility of capital losses is subject to limitations.

Passive foreign investment company rules

If Atlantica Yield were a PFIC for any taxable year during which a U.S. Holder held shares, certain adverse U.S. federal income tax consequences may apply to the U.S. Holder. Atlantica Yield does not believe that it was a PFIC for its 2017 taxable year and does not expect to be a PFIC for its current taxable year or in the foreseeable future. However, PFIC status depends on the composition of a company's income and assets and the fair market value of its assets (including, among others, less than 25% owned equity investments) from time to time, as well as on the application of complex statutory and regulatory rules that are subject to potentially varying or changing interpretations. Accordingly, there can be no assurance that Atlantica Yield will not be considered a PFIC for any taxable year.

A non-U.S. corporation will be a PFIC in any taxable year in which, after taking into account the income and assets of the corporation and certain subsidiaries pursuant to applicable "look-through rules," either: (i) at least 75% of its gross income is "passive income" or (ii) at least 50% of the average value of its assets is attributable to assets which produce passive income or are held for the production of passive income. For purposes of the PFIC rules, "passive income" includes, among other things, certain foreign currency gains, certain rents and the excess of gains over losses from certain commodities transactions. Gains from commodities transactions, however, are generally excluded from the definition of passive income if such gains are active business gains from the sale of commodities and the foreign corporation's commodities meet specified criteria. The law is unclear as to what constitutes "active business gains" and there are also other uncertainties regarding the criteria that commodities must meet. Accordingly, there can be no assurance that Atlantica Yield is not, was not for its 2017 taxable year, or will not become a PFIC or that changes in the management or ownership structure of Atlantica Yield or its assets, including as a result of any acquisitions pursuant to the ROFO Agreements, will not impact the determination of Atlantica Yield's PFIC status.

If Atlantica Yield were a PFIC for any taxable year during which a U.S. Holder held shares, gain recognized by a U.S. Holder on a sale or other disposition of the shares would generally be allocated ratably over the U.S. Holder's holding period for the shares. The amounts allocated to the taxable year of the sale or other disposition and to any year before Atlantica Yield became a PFIC would be taxed as ordinary income. The amount allocated to each other taxable year would be subject to U.S. federal income tax at the highest rate in effect in that year for individuals or corporations, as appropriate, and an interest charge would be imposed on the resulting U.S. federal income tax liability. The same treatment would generally apply to any distribution in respect of shares to the extent the distribution exceeds 125% of the average of the annual distributions on shares received by the U.S. Holder during the preceding three years or the U.S. Holder's holding period, whichever is shorter. Certain elections may be available that would result in alternative treatments (such as mark-to-market treatment) of the shares.

In addition, if Atlantica Yield were a PFIC for a taxable year in which it pays a dividend or in the prior taxable year, the favorable dividend rate discussed above with respect to dividends paid to certain non-corporate U.S. Holders would not apply.

U.S. Holders should consult their own tax advisors regarding the PFIC rules.

Information reporting and backup withholding

Payments of dividends and sales proceeds that are made within the United States or through certain U.S. financial intermediaries generally are subject to information reporting and to backup withholding unless the U.S. Holder is a corporation or other exempt recipient, or, in the case of backup withholding, the U.S. Holder provides a correct taxpayer identification number and certifies that it is not subject to backup withholding. The amount of any backup withholding from a payment to a U.S. Holder will be allowed as a credit against the U.S. Holder's U.S. federal income tax liability and may entitle such U.S. Holder to a refund, provided that the required information is timely furnished to the Internal Revenue Service. U.S. Holders should consult their own tax advisors about these rules and any other reporting obligations that may apply to the ownership or disposal of shares, including requirements related to the holding of certain "specified foreign financial assets."

F. Dividends and Paying Agents

Not applicable.

G. Statement by Experts

Not applicable.

H. Documents on Display

We have filed this annual report on Form 20-F with the SEC under the Securities Exchange Act of 1934, as amended. Statements made in this annual report as to the contents of any document referred to are not necessarily complete. With respect to each such document filed as an exhibit to this annual report, reference is made to the exhibit for a more complete description of the matter involved, and each such statement shall be deemed qualified in its entirety by such reference.

We are subject to the informational requirements of the Exchange Act and file reports and other information with the SEC. Reports and other information which we filed with the SEC, including this annual report on Form 20-F, may be inspected and copied at the public reference room of the SEC at 450 Fifth Street N.W. Washington D.C. 20549.

You can also obtain copies of this annual report on Form 20-F by mail from the Public Reference Section of the Securities and Exchange Commission, 450 Fifth Street, N.W., Washington D.C. 20549, at prescribed rates. Additionally, copies of this material may be obtained from the SEC's Internet site at http://www.sec.gov. The SEC's telephone number is 1-800-SEC-0330.

I. Subsidiaries Information

Not applicable.

ITEM 11. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Quantitative and Qualitative Disclosure about Market Risk

Our activities are undertaken through our segments and are exposed to market risk, credit risk and liquidity risk. Risk is managed by our Risk Management and Finance Department in accordance with mandatory internal management rules. The internal management rules provide written policies for the management of overall risk, as well as for specific areas, such as exchange rate risk, interest rate risk, credit risk, liquidity risk, use of hedging instruments and derivatives and the investment of excess cash.

Market risk

We are exposed to market risk, such as movement in foreign exchange rates and interest rates. All of these market risks arise in the normal course of business and we do not carry out speculative operations. For the purpose of managing these risks, we use a series of swaps and options on interest rates and foreign exchange rates. None of the derivative contracts signed has an unlimited loss exposure.

Foreign exchange rate risk

The main cash flows from our subsidiaries are cash collections arising from long-term contracts with clients and debt payments arising from project finance repayment. Given that financing of the projects is always denominated in the same currency in which the contract with the client is signed, a natural hedge exists for our main operations.

Our functional currency is the U.S. dollar, as most of our revenues and expenses are denominated or linked to U.S. dollars. All our companies located in North America, South America and Algeria have their PPAs, or concessional agreements, and financing contracts signed in, or indexed to, U.S. dollars. Our solar power plants in Spain have their revenues and expenses denominated in euros. Revenues and expenses of Kaxu, our solar plant in South Africa, are denominated in South African rand. While fluctuations in the value of the euro and the South African rand may affect our operating results, we hedge cash distributions from our Spanish assets. Our strategy is to hedge the exchange rate for the distributions from our Spanish assets after deducting euro-denominated interest payments and euro-denominated general and administrative expenses. Through currency options, we hedge 100% of the net euro net exposure for the next 12 months and 75% of the net euro net exposure for the following 12 months.

Since we hedge cash flows, fluctuations in the value of foreign currencies (the euro and the South African rand) in relation to the U.S. dollar may affect our operating results.

Interest rate risk

Interest rate risks arise mainly from our financial liabilities at variable interest rate (less than 10% of our total project debt financing). We use interest rate swaps and interest rate options (caps) to mitigate interest rate risk.

As a result, the notional amounts hedged as of December 31, 2017, contracted strikes and maturities, depending on the characteristics of the debt on which the interest rate risk is being hedged, are very diverse, including the following:

- project debt in U.S. dollars: between 70% and 100% of the notional amount, maturities until 2032 and average guaranteed interest rates of between 2.32% and 5.27%

- project debt in euro: between 87% and 100% of the notional amount, maturities until 2030 and average guaranteed interest rates of between 3.20% and 4.87%

In connection with our interest rate derivative positions, the most significant impact on our Annual Consolidated Financial Statements are derived from the changes in EURIBOR or LIBOR, which represents the reference interest rate for the majority of our debt.

In relation to our interest rate swaps positions, an increase in EURIBOR or LIBOR above the contracted fixed interest rate would create an increase in our financial expense which would be positively mitigated by our hedges, reducing our financial expense to our contracted fixed interest rate. However, an increase in EURIBOR or LIBOR that does not exceed the contracted fixed interest rate would not be offset by our derivative position and would result in a net financial loss recognized in our consolidated income statement. Conversely, a decrease in EURIBOR or LIBOR below the contracted fixed interest rate would result in lower interest expense on our variable rate debt, which would be offset by a negative impact from the mark-to-market of our hedges, increasing our financial expense up to our contracted fixed interest rate, thus likely resulting in a neutral effect.

In relation to our interest rate options positions, an increase in EURIBOR or LIBOR above the strike price would result in higher interest expenses, which would be positively mitigated by our hedges, reducing our financial expense to our capped interest rate, whereas a decrease of EURIBOR or LIBOR below the strike price would result in lower interest expenses.

In addition to the above, our results of operations can be affected by changes in interest rates with respect to the unhedged portion of our indebtedness that bears interest at floating rates.

In the event that EURIBOR and LIBOR had risen by 25 basis points as of December 31, 2017, with the rest of the variables remaining constant, the effect in the consolidated income statement would have been a loss of $0.2 million (a loss of $2.6 million in 2016 and a loss of $1.8 million in 2015) and an increase in hedging reserves of $37.8 million ($37.3 million in 2016 and $41.7 million in 2015). The increase in hedging reserves would be mainly due to an increase in the fair value of interest rate swaps designated as hedges.

Credit risk

We consider that we have limited credit risk with clients as revenues are derived from PPAs and other revenue contracted agreements with electric utilities and state-owned entities.

The following table shows the maturity detail of trade receivables as of December 31, 2017, 2016 and 2015:

	Balance as of December 31,		
	2017	**2016**	**2015**
		($ in millions)	
Maturity			
Up to 3 months	186.7	151.2	126.8
Between 3 and 6 months	—	—	—
Total	**186.7**	**151.2**	**126.8**

Liquidity risk

The objective of our financing and liquidity policy is to ensure that we maintain sufficient funds to meet our financial obligations as they fall due.

Project finance borrowing permits us to finance projects through project debt and thereby insulate the rest of our assets from such credit exposure. We incur project finance debt on a project-by-project basis.

The repayment profile of each project is established on the basis of the projected cash flow generation of the business. This ensures that sufficient financing is available to meet deadlines and maturities, which mitigates the liquidity risk significantly.

ITEM 12. DESCRIPTION OF SECURITIES OTHER THAN EQUITY SECURITIES

A. Debt Securities

Not applicable.

B. Warrants and Rights

Not applicable.

C. Other Securities

Not applicable.

D. American Depositary Shares

Not applicable.

PART II

ITEM 13. DEFAULTS, DIVIDEND ARREARAGES AND DELINQUENCIES

None.

ITEM 14. MATERIAL MODIFICATIONS TO THE RIGHTS OF SECURITY HOLDERS AND USE OF PROCEEDS

Not applicable.

ITEM 15. CONTROLS AND PROCEDURES

(a) Evaluation of Disclosure Controls and Procedures

We maintain disclosure controls and procedures, as defined in Rules 13a-15(e) and 15d-15(e) of the U.S. Exchange Act, that are designed to ensure that information required to be disclosed by the Company in reports that we file or submit under the U.S. Exchange Act is (i) recorded, processed, summarized and reported within the time period specified in the SEC's rules and forms; and (ii) accumulated and communicated to our management, including our Chief Executive Officer (principal executive officer) and Chief Financial Officer (principal financial officer), as appropriate, to allow timely decisions regarding required disclosure. Disclosure controls and procedures, no matter how well designed, can provide only reasonable assurance of achieving the desired control objectives.

Our management, with the participation of our Chief Executive Officer and Chief Financial Officer, has performed an evaluation of the effectiveness of the design and operation of its disclosure controls and procedures (as defined in Rule 13a-15 (e) under the Exchange Act) as of December 31, 2017. There are inherent limitations to the effectiveness of any control system, including disclosure controls and procedures.

Based upon their evaluation, our Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures are effective.

Management's Report on Internal Control over Financial Reporting

Pursuant to Section 404 of the United States Sarbanes-Oxley Act, management is responsible for establishing and maintaining effective internal control over financial reporting. This system is 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.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect all 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.

Our management assessed the effectiveness of our internal control over financial reporting as of December 31, 2017, based on the framework set forth by the Committee of Sponsoring Organizations of the Treadway Commission, or COSO, in Internal Control—Integrated Framework (2013). Based on this assessment, management concluded that, as of December 31, 2017, its internal control over financial reporting was effective based on those criteria.

Our internal control over financial reporting as of December 31, 2017, has been audited by Deloitte S.L., an independent registered public accounting firm, as stated in their report which follows below.

Attestation Report of the Independent Registered Public Accounting Firm

The report of Deloitte, S.L., our Independent Registered Public Accounting Firm, on our internal control over financial reporting is included herein at page F-2 of our Annual Consolidated Financial Statements.

Changes in Internal Controls over Financial Reporting

There has been no change in our internal control over financial reporting that occurred during 2017 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

ITEM 16. [RESERVED]

ITEM 16A. AUDIT COMMITTEE FINANCIAL EXPERT

See "Item 6.C—Board Practices—Audit Committee." Our board of directors has determined that Mr. Francisco J. Martinez and Mr. Daniel Villalba qualify as "audit committee financial experts" under applicable SEC rules.

ITEM 16B. CODE OF ETHICS

Our board of directors has adopted a code of conduct for our employees, officers and directors to govern their relations with current and potential customers, fellow employees, competitors, government and self-regulatory agencies, the media, and anyone else with whom we have contact. Our code of conduct is publicly available on our website at www.atlanticayield.com and it is under review on yearly basis.

ITEM 16C. PRINCIPAL ACCOUNTANT FEES AND SERVICES

The following table provides information on the aggregate fees billed by our principal accountants, Deloitte, S.L. and Deloitte LLP, classified by type of service rendered in 2017:

	Deloitte	Other Auditors	Total
		($ in thousands)	
Audit Fees	1,689	15	1,704
Audit-Related Fees	303	-	303
Tax Fees	-	-	-
All Other Fees	25	-	25
Total	**2,017**	**15**	**2,032**

The following table provides information on the aggregate fees billed by our principal accountants, Deloitte, S.L., to Atlantica Yield, classified by type of service rendered in 2016:

	Deloitte(1)	Other Auditors(1)	Total(1)
		($ in thousands)	
Audit Fees	1,553	15	1,568
Audit-Related Fees	118	-	118
Tax Fees	-	-	-
All Other Fees	19	-	19
Total	**1,690**	**15**	**1,705**

Note:—

(1) Aggregate fees for the year ended December 31, 2016 have been adjusted to conform to the criteria used for the year ended December 31, 2017

Audit Fees are the aggregate fees billed for professional services in connection with the audit of our Annual Consolidated Financial Statements, quarterly reviews of our interim financial statements and statutory audits of our subsidiaries' financial statements under the rules of England and Wales and the countries in which our subsidiaries are organized. Also included are services that can only be provided by our auditor, such as audits of non-recurring transactions, consents, comfort letters, attestation services and any audit services required for SEC or other regulatory filings. The increase in audit fees is mainly due to foreign exchange differences.

Audit-Related Fees are fees charged for assurance and related services that are reasonably related to the performance of the audit or review of our financial statements and are not restricted to those that can only be provided by the auditor signing the auditor's report. This category comprises fees billed advisory services associated with our financial reporting process and assistance with training of personnel in financial related subjects.

The Audit Committee approved all of the services provided by Deloitte, S.L. and by other member firms of Deloitte.

All Other Fees comprises fees billed in relation to financial advisory services and other services which cannot be comprised under other categories.

Audit Committee's Policy on Pre-Approval of Audit and Permissible Non-Audit Services of the Independent Auditor

Subject to the approval of the independent auditor by our shareholders, the Audit Committee has the sole authority to appoint, retain or replace the independent auditor. The Audit Committee is also directly responsible for the compensation and oversight of the work of the independent auditor. These policies generally provide that we will not engage our independent auditors to render audit or non-audit services unless the service is specifically approved in advance by the Audit Committee. The Audit Committee's pre-approval policy, which covers audit and non-audit services provided to us or to any of our subsidiaries, is as follows:

- The Audit Committee shall review and approve in advance the annual plan and scope of work of the independent external auditor, including staffing of the audit, and shall (i) review with the independent external auditor any audit-related concerns and management's response and (ii) confirm that any examination is performed in accordance with the relevant accounting standards;

- The Audit Committee shall pre-approve all audit services, and all permitted non-audit services (including the fees and terms thereof) to be performed for us by the independent auditors, to the extent required by law. The Audit Committee may delegate to one or more Committee members the authority to grant pre-approvals for audit and permitted non-audit services to be performed for us by the independent auditor, provided that decisions of such members to grant pre-approvals shall be presented to the full Audit Committee at its next regularly scheduled meeting;

- The list of audit services and all permitted non-audit services (including the fees and terms thereof) to be performed for us by the independent auditors pre-approved by the Audit Committee, considering that these services clearly allowed from the point of independence is the following:

- o Audit services, including audit of financial statements, limited reviews, comfort letters, other verification works requested by regulator or supervisors;

- o Audit-related services, including due diligence services, verification of corporate social responsibility report, accounting or internal control advisory and preparation courses on these topics;

- Tax services;

- Other specific services, such as evaluation of the design, implementation and operation of a financial information system or control over financial reporting; and

- Courses or seminars.

Only for information purposes, all audit and non-audit services will be reported to the Audit Committee on a quarterly basis.

Any other service shall be pre-approved by the Audit Committee. However, when for reasons of urgency, it is necessary to start the provision of services prior to the next meeting of the Audit Committee, the Chairman of the Audit Committee is authorized to provide such approval, which shall be communicated to the Audit Committee subsequently.

In accordance with the above pre-approval policy, all audit and permitted non-audit services performed for us by our principal accountants, or any of its affiliates, were approved by the Audit Committee of our board of directors, who concluded that the provision of such services by the independent accountants was compatible with the maintenance of that firm’s independence in the conduct of its auditing functions: an auditor may not function in the role of management; an auditor may not audit his or her own work; and an auditor may not serve in an advocacy role for his or her client.

The Audit Committee approved all the services provided by Deloitte, S.L.

ITEM 16D. EXEMPTIONS FROM THE LISTING STANDARDS FOR AUDIT COMMITTEES

Not applicable.

ITEM 16E. PURCHASES OF EQUITY SECURITIES BY THE ISSUER AND AFFILIATED PURCHASERS

Not applicable.

ITEM 16F. CHANGE IN REGISTRANT’S CERTIFYING ACCOUNTANT

Not applicable.

ITEM 16G. CORPORATE GOVERNANCE

Under the U.S. federal securities laws and the NASDAQ rules we are a “foreign private issuer.” Under NASDAQ Stock Market Rule 5615(a)(3), a foreign private issuer may follow home country corporate governance practices instead of certain of NASDAQ’s requirements. A foreign private issuer that elects to follow a home country practice instead of NASDAQ’s requirements must submit to NASDAQ a written statement from an independent counsel in such issuer’s home country certifying that the issuer’s practices are not prohibited by the home country’s laws. Specifically, as a foreign private issuer and as a UK company, although we are not required, we do have: (i) a majority of independent directors, (ii) a nominating/corporate governance committee composed entirely of independent directors and (iii) a compensation committee composed entirely of independent directors. However, as a foreign private issuer, and as a UK company, we are not required and do not have: (1) an annual performance evaluation of the nominating/corporate governance and compensation committees and (ii) regularly scheduled meetings at which only independent directors are present. These exemptions do not modify the independence requirements for the audit committee, and we currently comply with the requirements of the Sarbanes-Oxley Act and the NASDAQ rules.

ITEM 16H. MINE SAFETY DISCLOSURE

Not applicable.

PART III

ITEM 17. FINANCIAL STATEMENTS

We have elected to provide financial statements pursuant to Item 18.

ITEM 18. FINANCIAL STATEMENTS

Our Annual Consolidated Financial Statements are included at the end of this annual report.

ITEM 19. EXHIBITS

The following exhibits are filed as part of this annual report:

Exhibit No.	Description
1.1	Articles of Association of Atlantica Yield plc (incorporated by reference from Exhibit 3.1 to Atlantica Yield plc’s Form 6-K filed with the SEC on May 26, 2016 – SEC File No. 001-36487).
4.1	Amended and Restated Right of First Offer Agreement by and between Abengoa Yield plc (now Atlantica Yield plc) and Abengoa, S.A., dated December 9, 2014 (incorporated by reference from Exhibit 10.1 to Atlantica Yield plc’s Registration Statement on Form F-1 filed with the SEC on December 11, 2014 – SEC File No. 333-200848).
4.2	Amended and Restated Financial Support Agreement by and between Atlantica Yield plc and Abengoa, S.A. (incorporated by reference from Exhibit 4.2 to Atlantica Yield plc’s Form 6-K submitted to the SEC on November 13, 2017 – SEC File No. 001-36487).
4.5	Operation and Maintenance Agreement between Abengoa Solar Espana, S.A. and Solaben Electricidad Dos, S.A., dated December 10, 2012 (incorporated by reference from Exhibit 10.8 to Atlantica Yield plc’s draft registration statement on Form F-1 submitted to the SEC on February 28, 2014 – SEC File No. 377-00503).

4.6	Operation and Maintenance Agreement between Abengoa Solar Espana, S.A. and Solaben Electricidad Tres, S.A., dated December 10, 2012 (incorporated by reference from Exhibit 10.9 to Atlantica Yield plc's draft registration statement on Form F-1 submitted to the SEC on February 28, 2014 – SEC File No. 377-00503).
4.7	Indenture dated November 17, 2014, by and among Abengoa Yield plc (now Atlantica Yield plc), as issuer, Abengoa Concessions Peru, S.A., Abengoa Solar US Holdings Inc. and Abengoa Solar Holdings USA Inc., as guarantors, The Bank of New York Mellon, as trustee, registrar, paying agent and transfer agent, and The Bank of New York Mellon (Luxembourg) S.A., as Luxembourg paying agent and Luxembourg transfer agent, relating to the issuance and sale by Abengoa Yield plc (now Atlantica Yield plc) of $255,000,000 aggregate principal amount of 7.000% Senior Notes due 2019 (incorporated by reference from Exhibit 10.10 to Atlantica Yield plc's Registration Statement on Form F-1 filed with the SEC on December 11, 2014 – SEC File No. 333-200848).
4.8	Form of Global Notes relating to the issuance and sale by Abengoa Yield plc (now Atlantica Yield plc) of $255,000,000 aggregate principal amount of 7.000% Senior Notes due 2019 (incorporated by reference from Exhibit 10.10 to Atlantica Yield plc's Registration Statement on Form F-1 filed with the SEC on December 11, 2014 – SEC File No. 333-200848).
4.9	The Amended and Restated Credit and Guaranty agreement, dated June 26, 2015, among Abengoa Yield plc (now Atlantica Yield plc), the guarantors from time to time party thereto, HSBC Bank plc, HSBC Corporate Trust Company (UK) Limited, Bank of America, N.A., Banco Santander, S.A., Citigroup Global Markets Limited, RBC Capital Markets, Barclays Bank plc and UBS AG, London Branch (incorporated by reference from Exhibit 4.13 to Atlantica Yield plc's annual report on Form 20-F submitted to the SEC on March 1, 2015 – Sec File No. 001-36487).
4.10	The Note Issuance Facility, dated February 10, 2017, among Atlantica Yield plc, HSBC Corporate Trust Company (UK) Limited as collateral agent, Elavon Financial Services DAC, UK Branch as agent, and a group of funds managed by Westbourne Capital as purchasers of the notes issued thereunder (incorporated by reference from Exhibit 4.10 to Atlantica Yield plc's amendment to the annual report on Form 20-F/A submitted to the SEC on March 29, 2017 – SEC File No. 001-36487).
4.11	Amendment No. 1 to the Note Issuance Facility Agreement among Atlantica Yield plc, HSBC Corporate Trust Company (UK) Limited as collateral agent, Elavon Financial Services DAC, UK Branch as agent and a group of funds managed by Westbourne Capital as purchasers of the notes issued thereunder, dated March 28, 2017 (incorporated by reference from Exhibit 4.11 to Atlantica Yield plc's amendment to the annual report on Form 20-F/A submitted to the SEC on March 29, 2017 – SEC File No. 001-36487).
4.12	Registration Rights Agreement dated March 28, 2017 among Atlantica Yield plc, Abengoa S.A., ACIL Luxco1 S.A. and GLAS Trust Corporation Limited as security agent (incorporated by reference from Exhibit 4.12 from Atlantica Yield plc's Form 6-K filed with the SEC on April 12, 2017 – SEC File No. 001-36487).
8.1	Subsidiaries of Atlantica Yield plc.
12.1	Certification of Santiago Seage, Chief Executive Officer of Atlantica Yield plc, pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
12.2	Certification of Francisco Martinez-Davis, Chief Financial Officer of Atlantica Yield plc, pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
13.1	Certification pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
15.1	Consent of Deloitte, S.L.
15.2	Consent of Deloitte Algerie S.á.r.l
99.1	Audited financial statements of Myah Bahr Honaine S.p.a as of December 31, 2017 and for the year ended December 31, 2017 and 2016

SIGNATURE

The registrant hereby certifies that it meets all of the requirements for filing on Form 20-F and that it has duly caused and authorized the undersigned to sign this annual report on its behalf.

Date: March 7, 2018

ATLANTICA YIELD PLC

By: /s/ Santiago Seage
Name: Santiago Seage
Title: Chief Executive Officer

ATLANTICA YIELD PLC

By: /s/ Francisco Martinez-Davis
Name: Francisco Martinez-Davis
Title: Chief Financial Officer

ATLANTICA YIELD PLC
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Annual Consolidated Financial Statements as of December 31, 2017 and 2016 and for the years ended December 31, 2017, 2016 and 2015

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the shareholders and the Board of Directors of Atlantica Yield plc:

Opinion on the Financial Statements

We have audited the accompanying consolidated statements of financial position of Atlantica Yield plc and subsidiaries (the "Company") as of December 31, 2017 and 2016, and the related consolidated income statements, the consolidated financial statements of comprehensive income, the consolidated statements of changes in equity and the consolidated cash flow statements for each of the three years in the period ended December 31, 2017, and the related notes (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2017 and 2016, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2017, in conformity with International Financial Reporting Standards as issued by the International Accounting Standards Board ("IFRS-IASB").

We have also 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 and our report dated February 27, 2018, expressed an unqualified opinion on the Company's internal control over financial reporting.

Basis for Opinion

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

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

/s/ Deloitte, S.L.

Madrid, Spain

February 27, 2018

We have served as the Company's auditor since 2014.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the shareholders and the Board of Directors of Atlantica Yield plc:

Opinion on Internal Control over Financial Reporting

We have audited the internal control over financial reporting of Atlantica Yield plc and subsidiaries (the "Company") 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 (COSO). In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2017, based on criteria established in *Internal Control — Integrated Framework (2013)* issued by COSO.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated financial statements as of and for the year ended December 31, 2017, of the Company and our report dated February 27, 2018, expressed an unqualified opinion on those financial statements.

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 on Internal Control over Financial Reporting*. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

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

Definition and Limitations of Internal Control over Financial Reporting

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

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

/s/ Deloitte, S.L.

Madrid, Spain

February 27, 2018

Consolidated statements of financial position as of December 31, 2017 and 2016

Amounts in thousands of U.S. dollars

	Note (1)	As of December 31, 2017	As of December 31, 2016
Assets			
Non-current assets			
Contracted concessional assets	6	9,084,270	8,924,272
Investments carried under the equity method	7	55,784	55,009
Other receivables accounts	8	37,012	65,951
Derivative assets	8&9	8,230	3,822
Financial investments	8	45,242	69,773
Deferred tax assets	18	165,136	202,891
Total non-current assets		**9,350,432**	**9,251,945**
Current assets			
Inventories		17,933	15,384
Trade receivables	11	186,728	151,199
Credits and other receivables	11	57,721	56,422
Clients and other receivables	8&11	244,449	207,621
Financial investments	8	210,138	228,038
Cash and cash equivalents	8&12	669,387	594,811
Total current assets		**1,141,907**	**1,045,854**
Total assets		**10,492,339**	**10,297,799**

(1) Notes 1 to 23 are an integral part of the consolidated financial statements

Consolidated statements of financial position as of December 31, 2017 and 2016

Amounts in thousands of U.S. dollars

	Note (1)	As of December 31, 2017	As of December 31, 2016
Equity and liabilities			
Equity attributable to the Company			
Share capital	13	10,022	10,022
Parent company reserves	13	2,163,229	2,268,457
Other reserves		80,968	52,797
Accumulated currency translation differences		(18,147)	(133,150)
Retained earnings	13	(477,214)	(365,410)
Non-controlling interest	13	136,595	126,395
Total equity		**1,895,453**	**1,959,111**
Non-current liabilities			
Long-term corporate debt	14	574,176	376,340
Borrowings		4,413,172	3,824,871
Notes and bonds		815,745	804,313
Long-term project debt	15	5,228,917	4,629,184
Grants and other liabilities	16	1,636,060	1,612,045
Related parties	10	141,031	101,750
Derivative liabilities	9	329,731	349,266
Deferred tax liabilities	18	186,583	95,037
Total non-current liabilities		**8,096,498**	**7,163,622**
Current liabilities			
Short-term corporate debt	14	68,907	291,861
Borrowings		215,117	674,058
Notes and bonds		31,174	27,225
Short-term project debt	15	246,291	701,283
Trade payables and other current liabilities	17	155,144	160,505
Income and other tax payables		30,046	21,417
Total current liabilities		**500,388**	**1,175,066**
Total equity and liabilities		**10,492,339**	**10,297,799**

(1) Notes 1 to 23 are an integral part of the consolidated financial statements

Consolidated income statements for the years ended December 31, 2017, 2016 and 2015

Amounts in thousands of U.S. dollars

	Note (1)	For the year ended December 31,		
		2017	**2016**	**2015**
Revenue	4	1,008,381	971,797	790,881
Other operating income	20	80,844	65,538	68,857
Raw materials and consumables used		(16,983)	(26,919)	(23,243)
Employee benefit expenses		(18,854)	(14,736)	(5,848)
Depreciation, amortization, and impairment charges	6	(310,960)	(332,925)	(261,301)
Other operating expenses	20	(284,461)	(260,318)	(224,828)
Operating profit		457,967	402,437	344,518
Financial income	21	1,007	3,298	3,464
Financial expense	21	(463,717)	(408,007)	(333,921)
Net exchange differences		(4,092)	(9,546)	3,852
Other financial income/(expense), net	21	18,434	8,505	(200,153)
Financial expense, net		(448,368)	(405,750)	(526,758)
Share of profit/(loss) of associates carried under the equity method	7	5,351	6,646	7,844
Profit/(loss) before income tax		14,950	3,333	(174,396)
Income tax	18	(119,837)	(1,666)	(23,790)
Profit/(loss) for the year		(104,887)	1,667	(198,186)
Loss/(profit) attributable to non-controlling interests		(6,917)	(6,522)	(10,819)
Profit/(loss) for the year attributable to the Company		(111,804)	(4,855)	(209,005)
Weighted average number of ordinary shares outstanding (thousands)	22	100,217	100,217	92,795
Basic earnings per share (U.S. dollar per share)	22	(1.12)	(0.05)	(2.25)

(1) Notes 1 to 23 are an integral part of the consolidated financial statements

Consolidated statements of comprehensive income for the years ended December 31, 2017, 2016 and 2015

Amounts in thousands of U.S. dollars

	For the year ended December 31,		
	2017	**2016**	**2015**
Profit/(loss) for the year	(104,887)	1,667	(198,186)
Items that may be subject to transfer to income statement			
Change in fair value of cash flow hedges	(28,535)	(37,480)	56
Currency translation differences	121,924	(22,150)	(91,405)
Tax effect	4,426	12,555	1,950
Net income/(expenses) recognized directly in equity	97,815	(47,075)	(89,399)
Cash flow hedges	70,953	72,774	55,841
Tax effect	(17,738)	(18,194)	(13,960)
Transfers to income statement	53,215	54,580	41,881
Other comprehensive income/(loss)	151,030	7,505	(47,518)
Total comprehensive income/(loss) for the year	46,143	9,172	(245,704)
Total comprehensive (income)/loss attributable to non-controlling interest	(14,773)	(9,629)	(3,550)
Total comprehensive income/(loss) attributable to the Company	31,370	(457)	(249,254)

Consolidated statements of changes in equity for the years ended December 31, 2017, 2016 and 2015

Amounts in thousands of U.S. dollars

	Share Capital	Parent company reserves	Other reserves	Retained earnings	Accumulated currency translation differences	Total equity attributable to the Company	Non-controlling interest	Total equity
Balance as of January 1, 2015	**8,000**	**1,790,135**	**(15,539)**	**(2,031)**	**(28,963)**	**1,751,602**	**88,029**	**1,839,631**
Profit/(loss) for the year after taxes	-	-	-	(209,005)	-	(209,005)	10,819	(198,186)
Change in fair value of cash flow hedges	-	-	51,215	-	-	51,215	4,682	55,897
Currency translation differences	-	-	-	-	(80,619)	(80,619)	(10,786)	(91,405)
Tax effect	-	-	(10,845)	-	-	(10,845)	(1,165)	(12,010)
Other comprehensive income	**-**	**-**	**40,370**	**-**	**(80,619)**	**(40,249)**	**(7,269)**	**(47,518)**
Total comprehensive income	**-**	**-**	**40,370**	**(209,005)**	**(80,619)**	**(249,254)**	**3,550**	**(245,704)**
Asset acquisition under the Rofo	**-**	**-**	**-**	**(145,488)**	**-**	**(145,488)**	**57,627**	**(87,861)**
Dividend distribution	**-**	**(137,995)**	**-**	**-**	**-**	**(137,995)**	**(8,307)**	**(146,302)**
Capital Increase	**2,022**	**661,715**	**-**	**-**	**-**	**663,737**	**-**	**663,737**
Balance as of December 31, 2015	**10,022**	**2,313,855**	**24,831**	**(356,524)**	**(109,582)**	**1,882,602**	**140,899**	**2,023,501**
Balance as of January 1, 2016	10,022	2,313,855	24,831	(356,524)	(109,582)	1,882,602	140,899	2,023,501
Profit/(loss) for the year after taxes	-	-	-	(4,855)	-	(4,855)	6,522	1,667
Change in fair value of cash flow hedges	-	-	32,944	-	-	32,944	2,350	35,294
Currency translation differences	-	-	-	-	(23,568)	(23,568)	1,418	(22,150)
Tax effect	-	-	(4,978)	-	-	(4,978)	(661)	(5,639)
Other comprehensive income	**-**	**-**	**27,966**	**-**	**(23,568)**	**4,398**	**3,107**	**7,505**
Total comprehensive income	**-**	**-**	**27,966**	**(4,855)**	**(23,568)**	**(457)**	**9,629**	**9,172**
Acquisition of non-controlling interest in Solacor 1&2 (a)	**-**	**-**	**-**	**(4,031)**	**-**	**(4,031)**	**(15,894)**	**(19,925)**
Asset acquisition (Seville PV) (a)	**-**		**-**	**-**	**-**		**713**	**713**
Dividend Distribution	**-**	**(45,398)**	**-**	**-**	**-**	**(45,398)**	**(8,952)**	**(54,350)**
Balance as of December 31, 2016	**10,022**	**2,268,457**	**52,797**	**(365,410)**	**(133,150)**	**1,832,716**	**126,395**	**1,959,111**

	Share Capital	Parent company reserves	Other reserves	Retained earnings	Accumulated currency translation differences	Total equity attributable to the Company	Non-controlling interest	Total equity
Balance as of January 1, 2017	**10,022**	**2,268,457**	**52,797**	**(365,410)**	**(133,150)**	**1,832,716**	**126,395**	**1,959,111**
Profit/(loss) for the year after taxes	-	-	-	(111,804)	-	(111,804)	6,917	(104,887)
Change in fair value of cash flow hedges	-	-	41,242	-	-	41,242	1,176	42,418
Currency translation differences	-	-	-	-	115,003	115,003	6,921	121,924
Tax effect	-	-	(13,071)	-	-	(13,071)	(241)	(13,312)
Other comprehensive income	**-**	**-**	**28,171**	**-**	**115,003**	**143,174**	**7,856**	**151,030**
Total comprehensive income	**-**	**-**	**28,171**	**(111,804)**	**115,003**	**31,370**	**14,773**	**46,143**
Dividend distribution	**-**	**(105,228)**	**-**	**-**	**-**	**(105,228)**	**(4,573)**	**(109,801)**
Balance as of December 31, 2017	**10,022**	**2,163,229**	**80,968**	**(477,214)**	**(18,147)**	**1,758,858**	**136,595**	**1,895,453**

(a) See Note 5 for further details.

Notes 1 to 23 are an integral part of the consolidated financial statements

Consolidated cash flow statements for the years ended December 31, 2017, 2016 and 2015

Amounts in thousands of U.S. dollars

	Note (1)	For the year ended 2017	2016	2015
I. Profit/(loss) for the year		**$ (104,887)**	**$ 1,667**	**$ (198,186)**
Non-monetary adjustments				
Depreciation, amortization and impairment charges	6	310,960	332,925	261,301
Financial (income)/expenses		443,517	397,966	553,300
Fair value (gains)/losses on derivative financial instruments		759	(1,761)	(4,292)
Shares of (profits)/losses from associates		(5,351)	(6,646)	(7,844)
Income tax	18	119,837	1,666	23,790
Changes in consolidation and other non-monetary items		(20,882)	(59,375)	(91,410)
II. Profit for the year adjusted by non monetary items		**$ 743,953**	**$ 666,442**	**$ 536,659**
Variations in working capital				
Inventories		(2,548)	(729)	(1,198)
Clients and other receivables		(23,799)	(15,001)	14,845
Trade payables and other current liabilities		22,474	11,422	9,994
Financial investments and other current assets/liabilities		(4,924)	6,341	49,420
III. Variations in working capital		**$ (8,797)**	**$ 2,033**	**$ 73,061**
Income tax received/(paid)		(4,779)	(1,953)	522
Interest received		4,139	3,342	1,600
Interest paid		(348,893)	(335,446)	(312,357)
A. Net cash provided by/(used in) operating activities		**$ 385,623**	**$ 334,418**	**$ 299,485**
Investments in entities under the equity method		3,003	4,984	4,417
Investments in contracted concessional assets*		30,058	(5,952)	(106,007)
Other non-current assets/liabilities		8,183	(3,637)	5,714
(Acquisitions)/Sales of subsidiaries and other financial instruments		30,124	(21,754)	(833,974)
B. Net cash used in investing activities		**$ 71,368**	**$ (26,359)**	**$ (929,850)**
Proceeds from Project & Corporate debt	14&15	296,398	11,113	459,366
Repayment of Project & Corporate debt	14&15	(613,242)	(182,636)	(175,389)
Dividends paid to Company´s shareholders		(99,483)	(35,509)	(137,166)
Proceeds from capital increase		—	—	664,120
Purchase of shares to non-controlling interests		—	(19,071)	—
C. Net cash provided by/(used in) financing activities		**$ (416,327)**	**$ (226,103)**	**$ 810,931**
Net increase/(decrease) in cash and cash equivalents		**$ 40,664**	**$ 81,956**	**$ 180,566**
Cash, cash equivalents and bank overdrafts at beginning of the year	12	594,811	514,712	354,154
Translation differences cash or cash equivalent		33,912	(1,857)	(20,008)
Cash and cash equivalents at the end of the year	12	**$ 669,387**	**$ 594,811**	**$ 514,712**

* Includes proceeds for $42.5 million and investments for $12.4 million (see Note 6).

(1) Notes 1 to 23 are an integral part of the consolidated financial statements

Contents

The Appendices are an integral part of the notes to the consolidated financial statements

Note 1.- Nature of the business

Atlantica Yield plc ("Atlantica Yield" or the "Company") was incorporated in England and Wales as a private limited company on December 17, 2013 under the name Abengoa Yield Limited. On March 19, 2014, the Company was re-registered as a public limited company, under the name Abengoa Yield plc. On May 13, 2016, the change of the Company´s registered name to Atlantica Yield plc was filed with the Registrar of Companies in the United Kingdom.

Atlantica Yield is a total return company that owns, manages and acquires renewable energy, efficient natural gas (previously denominated "conventional power") , electric transmission lines and water assets focused on North America (the United States and Mexico), South America (Peru, Chile and Uruguay) and EMEA (Spain, Algeria and South Africa).

The Company's largest shareholder is Abengoa S.A. ("Abengoa"), which, based on the most recent public information, currently owns a 41.47 % stake in Atlantica Yield. Abengoa does not consolidate the Company in its consolidated financial statements.

On June 18, 2014, Atlantica Yield closed its initial public offering issuing 24,850,000 ordinary shares. The shares were offered at a price of $29 per share, resulting in gross proceeds to the Company of $720,650 thousand. The underwriters further purchased 3,727,500 additional shares from the selling shareholder, a subsidiary wholly owned by Abengoa, at the public offering price less fees and commissions to cover over-allotments ("greenshoe") driving the total proceeds of the offering to $828,748 thousand.

Prior to the consummation of the initial public offering, Abengoa contributed, through a series of transactions, which we refer to collectively as the "Asset Transfer," ten concessional assets, certain holding companies and a preferred equity investment in Abengoa Concessoes Brasil Holding ("ACBH"), which is a subsidiary of Abengoa engaged in the development, construction, investment and management of contracted concessions in Brazil, comprised mostly of transmission lines. As consideration for the Asset Transfer, Abengoa received a 64.28% interest in Atlantica Yield and $655.3 million in cash, corresponding to the net proceeds of the initial public offering less $30 million retained by Atlantica Yield for liquidity purposes.

Atlantica Yield's shares began trading on the NASDAQ Global Select Market under the symbol "ABY" on June 12, 2014. The symbol changed to "AY" on November 11, 2017.

During 2016, the Company closed the acquisition of a 13% stake in Solacor 1/2 from the JGC Corporation ("JGC"), which reduced the JGC´s ownership in Solacor 1/2 to 13%, and of an 80% stake in Fotovoltaica Solar Sevilla, S.A. ("Seville PV") from Abengoa, a 1 MW solar photovoltaic plant in Spain.

On February 28, 2017, the Company closed the acquisition of a 12.5% interest in a 114-mile transmission line in the U.S. from Abengoa. The asset will receive a Federal Energy Regulatory Commission ("FERC") regulated rate of return, and is currently under development, with Commercial Operation Date ("COD") expected in 2020.

On July 20, 2017, the Company reached an agreement to acquire, subject to approvals from the relevant authorities in Peru, a 4 MW hydroelectric power plant in Peru for approximately $9 million.

The following table provides an overview of the concessional assets the Company owned as of December 31, 2017 (excluding the 12.5% interest in the transmission line in the U.S. acquired in February 2017):

Assets	Type	Ownership	Location	Currency[8]	Capacity (Gross)	Counterparty Credit Ratings[9]	COD*	Contract Years Left [12]
Solana	Renewable (Solar)	100% Class B[1]	Arizona (USA)	USD	280 MW	A-/A3/A-	4Q 2013	26
Mojave	Renewable (Solar)	100%	California (USA)	USD	280 MW	A-/A3/A-	4Q 2014	22
Solaben 2 & 3	Renewable (Solar)	70%[2]	Spain	Euro	2x50 MW	BBB+/Baa2/A-	3Q 2012 & 2Q 2012	20&19
Solacor 1 & 2	Renewable (Solar)	87%[3]	Spain	Euro	2x50 MW	BBB+/Baa2/A-	1Q 2012 & 1Q 2012	19
PS10/PS20	Renewable (Solar)	100%	Spain	Euro	31 MW	BBB+/Baa2/A-	1Q 2007 & 2Q 2009	14&16
Helioenergy 1 & 2	Renewable (Solar)	100%	Spain	Euro	2x50 MW	BBB+/Baa2/A-	3Q 2011& 4Q 2011	19
Helios 1 & 2	Renewable (Solar)	100%	Spain	Euro	2x50 MW	BBB+/Baa2/A-	3Q 2012& 3Q 2012	20
Solnova 1, 3 & 4	Renewable (Solar)	100%	Spain	Euro	3x50 MW	BBB+/Baa2/A-	2Q 2010 & 2Q 2010& 3Q 2010	17&17&18
Solaben 1 & 6	Renewable (Solar)	100%	Spain	Euro	2x50 MW	BBB+/Baa2/A-	3Q 2013	21
Kaxu	Renewable (Solar)	51%[4]	South Africa	Rand	100 MW	BB/Baa3/BB+[10]	1Q 2015	17
Palmatir	Renewable (Wind)	100%	Uruguay	USD	50 MW	BBB/Baa2/BBB-[11]	2Q 2014	16
Cadonal	Renewable (Wind)	100%	Uruguay	USD	50 MW	BBB/Baa2/BBB-[11]	4Q 2014	17
ACT	Efficient natural gas	100%	Mexico	USD	300 MW	BBB+/A3/ BBB+	2Q 2013	15
ATN	Transmission line	100%	Peru	USD	362 miles	BBB+/A3/BBB+	1Q 2011	23
ATS	Transmission line	100%	Peru	USD	569 miles	BBB+/A3/BBB+	1Q 2014	26
ATN 2	Transmission line	100%	Peru	USD	81 miles	Not rated	2Q 2015	15
Quadra 1	Transmission line	100%	Chile	USD	49 miles	Not rated	2Q 2014	17
Quadra 2	Transmission line	100%	Chile	USD	32 miles	Not rated	1Q 2014	17
Palmucho	Transmission line	100%	Chile	USD	6 miles	BBB+/Baa2/BBB+	4Q 2007	20
Skikda	Water	34.2%[5]	Algeria	USD	3.5 M ft3/day	Not rated	1Q 2009	16
Honaine	Water	25.5%[6]	Algeria	USD	7 M ft3/ day	Not rated	3Q 2012	20
Seville PV	Renewable (Solar)	80%[7]	Spain	Euro	1 MW	BBB+/Baa2/A-	3Q 2006	18

(1) On September 30, 2013, Liberty Interactive Corporation invested $300,000 thousand in Class A membership interests in exchange for a share of the dividends and taxable loss generated by Solana. As a result of the agreement, Liberty Interactive Corporation will receive between 54.06% and 61.20% of both dividends and taxable loss generated, additional amounts until the date Liberty reaches a certain rate of return or the "Flip Date", and 22.60% of both dividends and taxable loss generated thereafter.

(2) Itochu Corporation, a Japanese trading company, holds 30% of the shares in each of Solaben 2 and Solaben 3.

(3) JGC, a Japanese engineering company, holds 13% of the shares in each of Solacor 1 and Solacor 2.

(4) Kaxu is owned by the Company (51%), Industrial Development Corporation of South Africa (29%) and Kaxu Community Trust (20%).

(5) Algerian Energy Company, SPA owns 49% of Skikda and Valoriza Agua, S.L. owns the remaining 16.83%.

(6) Algerian Energy Company, SPA owns 49% of Honaine and Valoriza Agua, S.L. owns the remaining 25.5%.

(7) Instituto para la Diversificación y Ahorro de la Energía ("Idae"), a Spanish state owned company, holds 20% of the shares in Seville PV.

(8) Certain contracts denominated in U.S. dollars are payable in local currency.

(9) Reflects the counterparty's credit ratings issued by Standard & Poor's Ratings Services, or S&P, Moody's Investors Service Inc., or Moody's, and Fitch Ratings Ltd, or Fitch.

(10) Refers to the credit rating of the Republic of South Africa. The offtaker is Eskom, which is a state-owned utility company in South Africa.

(11) Refers to the credit rating of Uruguay, as UTE (Administración Nacional de Usinas y Transmisoras Eléctricas) is unrated.

(12) As of December 31, 2017.

* Commercial Operation Date ("COD").

On November 27, 2015 Abengoa, reported that, it filed a communication pursuant to article 5 bis of the Spanish Insolvency Law 22/2003 with the Mercantile Court of Seville nº 2. On November 8, 2016, the Judge of the Mercantile Court of Seville declared judicial approval of Abengoa´s restructuring agreement, extending the terms of the agreement to those creditors who had not approved the restructuring agreement.

On February 3, 2017, Abengoa announced it obtained approval from creditors representing 94% of its financial debt after the supplemental accession period. On March 31, 2017 Abengoa announced the completion of the restructuring. As a result, Atlantica Yield received Abengoa debt and equity instruments in exchange of the guarantee previously provided by Abengoa regarding the preferred equity investment in ACBH. In addition, the Company invested in Abengoa´s issuance of asset-backed notes (the “New Money 1 Tradable Notes”) in order to convert the junior status of the Abengoa debt received into senior debt (see Note 8).

The financing arrangement of Kaxu contained as of December 31, 2016 cross-default provisions related to Abengoa, such that debt defaults by Abengoa, subject to certain threshold amounts and/or a restructuring process, could trigger defaults under such project financing arrangement. In March 2017, the Company signed a waiver which gives clearance to cross-default that might have arisen from Abengoa insolvency and restructuring up to that date, but does not extend to potential future cross-default events.

The financing arrangement of Cadonal also contained cross-default provisions with Abengoa and a waiver was obtained in 2016, subject to certain conditions. These conditions were met in October 2017.

In addition, as of December 31, 2016 the financing arrangements of Kaxu, ACT, Solana and Mojave contained a change of ownership clause that would be triggered if Abengoa ceased to own at least 35% of Atlantica Yield’s shares (30% in the case of Solana and Mojave). Based on the most recent public information, Abengoa currently owns 41.47% of Atlantica Yield shares and 41.44% of the outstanding shares have been pledged as guarantee of the New Money 1 Tradable Notes and loans. On November 1, 2017 Abengoa announced it has reached an agreement with Algonquin Power & Utilities Corp. (“Algonquin”) to sell a 25% stake in Atlantica Yield subject to conditions precedent. Additionally, Abengoa has communicated that it intends to sell its remaining 16.5% stake over the upcoming months in a private transaction subject to approval by the U.S. Department of Energy (the “DOE”). Algonquin has an option to purchase this remaining stake until March 2018, according to public information. If Abengoa ceases to comply with its obligation to maintain its 30% ownership of Atlantica Yield ‘s shares, such reduced ownership would put the Company in breach of covenants under the applicable project financing arrangements.

In the case of Solana and Mojave, a forbearance agreement signed with the DOE in 2016 with respect to these assets allows reductions of Abengoa’s ownership of the shares of the Company if it results from (i) a sale or other disposition at any time pursuant and in connection with a subsequent insolvency proceeding by Abengoa, or (ii) capital increases by the Company. In other events of reduction of ownership by Abengoa below the minimum ownership threshold such as sales of stake in Atlantica Yield by Abengoa, the available DOE remedies will not include debt acceleration, but DOE remedies available could include limitations on distributions to the Company from Solana and Mojave. In addition, the minimum ownership threshold for Abengoa’s ownership of the shares of the Company has been reduced from 35% to 30%. In November 2017, in the context of the agreement reached between Abengoa and Algonquin for the acquisition by Algonquin of 25% of the shares of the Company and based on the obligations of Abengoa under the EPC contract the Company signed a consent with the DOE which reduces this minimum ownership required by Abengoa in Atlantica Yield to 16%, subject to certain conditions precedent most of which are beyond the control of Atlantica Yield (see Note 10).

In the case of Kaxu, in March 2017 the Company signed a waiver, which allows reduction of ownership by Abengoa below the 35% threshold if it is done in the context of the restructuring plan. Additionally, the Company obtained in October 2017 the waiver for ACT

Additionally, on February 10, 2017, the Company issued senior secured notes (the “Note Issuance Facility”) with a group of funds managed by Westbourne Capital as purchasers of the notes issued thereunder for a total amount of €275 million (approximately $330 million as of December 31, 2017). The proceeds of the Note Issuance Facility were used to fully repay Tranche B under the Company´s Credit Facility, which was then canceled (see Note 14).

These consolidated financial statements were approved by the Board of Directors of the Company on February 27, 2018.

Note 2.- Significant accounting policies

2.1 Basis of preparation

These consolidated financial statements are presented in accordance with the International Financial Reporting Standards (“IFRS”) as issued by the International Accounting Standards Board (“IASB”).

The Company entered into an agreement with Abengoa on June 13, 2014 (the “ROFO Agreement”), as amended and restated on December 9, 2014, that provides the Company with a right of first offer on any proposed sale, transfer or other disposition of any of Abengoa’s contracted renewable energy, efficient natural gas, electric transmission or water assets in operation and located in the United States, Canada, Mexico, Chile, Peru, Uruguay, Brazil, Colombia and the European Union, as well as four assets in selected countries in Africa, the Middle East and Asia.

The Company elected to account for the assets acquisitions under the ROFO Agreement using the Predecessor values as long as Abengoa had control over the Company, given that these were transactions between entities under common control. Any difference between the consideration given and the aggregate book value of the assets and liabilities of the acquired entities as of the date of the transaction has been reflected as an adjustment to equity.

Abengoa has no control over the Company since December 31, 2015. Therefore, any acquisition from Abengoa is accounted for in the consolidated accounts of Atlantica Yield since December 31, 2015, in accordance with IFRS 3, Business Combination.

The consolidated financial statements are presented in U.S. dollars, which is the Company’s functional and presentation currency. Amounts included in these consolidated financial statements are all expressed in thousands of U.S. dollars, unless otherwise indicated.

Application of new accounting standards

a) Standards, interpretations and amendments effective from January 1, 2017 under IFRS-IASB, applied by the Company in the preparation of these consolidated financial statements:

- IAS 7 (Amendment) ‘Disclosure Initiative’. Requirements for additional disclosures in order to provide users with improved financial information.

- IAS 12 (Amendment) ‘Recognition for Deferred Tax for Unrealized Losses’. Clarification of recognition of deferred tax assets for unrealized losses.

- Annual Improvements to IFRSs 2014-2016 cycles. Amendments to IFRS 12.

The applications of these amendments have not had any material impact on these consolidated financial statements except for the reconciliation of liabilities arising from financial activities that has been included in Note 14 and 15.

b) Standards, interpretations and amendments published by the IASB that will be effective for periods beginning on or after January 1, 2018:

- IFRS 9 'Financial Instruments'. This Standard is applicable for annual periods beginning on or after January 1, 2018 under IFRS-IASB, earlier application is permitted.

- IFRS 9 (Amendments to IFRS 9): Prepayment Features with Negative Compensation. This Standard is applicable for annual periods beginning on or after January 1, 2019 under IFRS-IASB, earlier application is permitted.

- IFRS 15 'Revenues from Contracts with Customers'. This Standard is applicable for annual periods beginning on or after January 1, 2018 under IFRS-IASB, earlier application is permitted.

- IFRS 15 (Clarifications) 'Revenues from Contracts with Customers'. This amendment is mandatory for annual periods beginning on or after January 1, 2018 under IFRS-IASB, earlier application is permitted.

- IFRS 16 'Leases'. This Standard is applicable for annual periods beginning on or after January 1, 2019 under IFRS-IASB, earlier application is permitted.

- IFRS 17 'Insurance Contracts'. This Standard is applicable for annual periods beginning on or after January 1, 2021 under IFRS-IASB, earlier application is permitted.

- IFRS 2 (Amendment) 'Classification and Measurement of Share-based Payment Transactions'. This amendment is mandatory for annual periods beginning on or after January 1, 2018 under IFRS-IASB, earlier application is permitted.

- IFRS 4 (Amendment). Applying IFRS 9 'Financial Instruments' with IFRS 4 'Insurance Contracts'. This amendment is mandatory for annual periods beginning on or after January 1, 2018 under IFRS-IASB, earlier application is permitted.

- IAS 40 (Amendment). Transfers of Investment Property. This amendment is mandatory for annual periods beginning on or after January 1, 2018 under IFRS-IASB, earlier application is permitted.

- IAS 19 (Amendment). Amendments to IAS 19: Plan Amendment, Curtailment or Settlement. This amendment is mandatory for annual periods beginning on or after January 1, 2019 under IFRS-IASB, earlier application is permitted.

- IAS 28 (Amendment). Long-term Interests in Associates and Joint Ventures. This amendment is mandatory for annual periods beginning on or after January 1, 2018 under IFRS-IASB, earlier application is permitted.

- Annual Improvements to IFRSs 2014-2016 cycles. Other minor amendments and modifications different from the aforementioned on IFRS 12. This Standard is applicable for annual periods beginning on or after January 1, 2018 under IFRS-IASB.

- Annual Improvements to IFRSs 2015-2017 cycles. This Standard is applicable for annual periods beginning on or after January 1, 2018 under IFRS-IASB.

- IFRIC 22 Foreign Currency Transactions and Advance Consideration. This Standard is applicable for annual periods beginning on or after January 1, 2018 under IFRS-IASB.

- IFRIC 23 Uncertainty over Income Tax Treatments. This Standard is applicable for annual periods beginning on or after January 1, 2019 under IFRS-IASB.

- IFRS 10 and IAS 28. Parent disposes of (or contributes) its controlling interest in a subsidiary to an existing associate or joint venture. Effective date beginning on or after a date to be determined by the IASB.

The application of these accounting standards is not expected to have a material impact on the consolidated financial statements of the Company.

The analysis performed by the Company, relating to the impact of the new relevant accounting standards is as follows:

IFRS 15 'Revenues from contracts with Customers'

In May 2014, the IASB (International Accounting Standards Board) published IFRS 15 "Recognition of Revenue from Contracts with Customers". This Standard brings together all the applicable requirements and replaces the current standards for recognizing revenue: IAS 11 Construction Contracts, IAS 18 Revenue, IFRIC 13 Customer Loyalty Program, IFRIC 15 Agreements for the Construction of Real Estate, IFRIC 18 Transfers of Assets from Customers and SIC-31 Revenue—Barter Transactions Involving Advertising Services.

The new requirements may lead to changes in the current revenue profile, since the Standard's main principle is that the Company must recognize its revenue in accordance with the transfer of goods or services to the customers in an amount which reflects the consideration that the Company expects to receive in exchange for these goods or services. The model laid out by the Standard is structured in five steps:

- Step 1: Identifying the contract with the customer.
- Step 2: Identifying the performance obligations.
- Step 3: Determining the transaction price.
- Step 4: Assigning the transaction price in the performance obligations identified in the contract.
- Step 5: Recognition of revenue when (or as) the Company performs the performance obligations.

Contracted concessional assets and price purchase agreements (PPAs) include fixed assets financed through project debt, related to service concession arrangements recorded in accordance with International Financial Reporting Interpretations Committee 12 ("IFRIC 12"), except for Palmucho, which is recorded in accordance with IAS 17 and PS10, PS20 and Seville PV, which are recorded as tangible assets in accordance with IAS 16. The infrastructures accounted for by the Company as concessions are related to the activities concerning electric transmission lines, solar electricity generation plants, cogeneration plants, wind farms and water plants.

Currently, assets recorded in accordance with IFRIC 12 are classified as intangible assets or as financial assets, depending on the nature of the payment entitlements established in the contracts.

According to IFRS 15, the Company should assess the goods and services promised in the contracts with the customers and shall identify as a performance obligation each promise to transfer to the customer a good or service (or a bundle of goods or services).

In the case of contracts related to financial assets, the Company has identified two performance obligations (construction and operation of the asset). The contracts state that each service (construction and operation) has its own transaction price. For this reason, both performance obligations are separately identifiable in the context of the contract. The Company must allocate the total consideration to be received by the contract to each performance obligation. As mentioned above, the different services performed have been identified as two different performance obligations (construction and operation). Each performance obligation has its own transaction price stated in the contract. Such transaction prices are agreed in the contract by the parties in an orderly transaction, with no interrelation between both transaction prices and therefore correspond to the fair value of the goods and services provided in each case. As a result, for IFRS 15 purposes, the total transaction price will be allocated to each performance obligation in accordance with the two transaction prices stated within the contract, as they represent the respective fair values of the identified performance obligations.

For the assets classified as intangible assets, the Company has identified the same performance obligations, (construction and operation), but in this case the consideration received by the Company for the construction services is a license. The grantor makes a non-cash payment for the construction services by giving the operator an intangible asset. When allocating fair value for IFRS 15 purposes, the Company will recognize as revenue for the first performance obligation the fair value of the construction services, and the amount corresponding to the sales of energy as the fair value of second performance obligation (operation).

Additionally, in both cases, the services are satisfied over time. Therefore, the Company satisfies the performance obligations and recognizes revenue over time. The same conclusion applies to concessional assets that are classified as tangible assets or leases.

IFRS 15 also incorporates specific criteria to determine which costs relating to a contract should be capitalized by distinguishing between incremental costs of obtaining a contract and costs associated with fulfilling a contract. No significant costs of obtaining a contract or compliance (other than those that are already capitalized) have been identified.

As the current practice for revenue recognition is consistent with the analysis above under IFRS 15, the Company considers that the adoption of this standard will not have impact in the consolidated financial statements of the Company.

Also, the Company has the intention to adopt IFRS 15 applying the full retrospective method to each prior reporting period presented, but without changes in the comparative reporting periods as the adoption of the standard has no effect in the financial statements.

IFRS 9 'Financial Instruments'

IFRS 9 Financial Instruments issued on 24 July 2014 is the IASB's replacement of IAS 39 Financial Instruments: Recognition and Measurement. The standard addresses the classification, measurement and derecognition of financial assets and financial liabilities, introduces new rules for hedge accounting and a new impairment model for financial assets. The Company will be adopting the standard as of January 1, 2018, including the new requirements for hedge accounting (which application is voluntary for 2018). The Company will be adopting retrospectively without re-expressing comparative periods. The analysis performed by the Company is as follows:

- Classification and measurement of financial instruments:

  a) Financial assets IFRS 9 classifies all financial assets that are currently in the scope of IAS 39 into two categories: amortized cost and fair value. Where assets are measured at fair value, gains and losses are either recognized entirely in profit or loss (fair value through profit or loss, "FVTPL"), or recognized in other comprehensive income (fair value through other comprehensive income, "FVTOCI"). The new guidance has no significant impact on the classification and measurement of the financial assets of the Company as the vast majority of financial assets (except for derivatives) are currently measured at amortized cost, and meet the conditions for classification at amortized cost under IFRS9. The Company has the intention of maintaining this classification.

  b) Financial liabilities: IFRS 9 does not change the basic accounting model for financial liabilities under IAS 39. Two measurement categories continue to exist: FVTPL and amortized cost. Financial liabilities held for trading are measured at FVTPL, and all other financial liabilities are measured at amortized cost unless the fair value option is applied. As a result, the Company concluded that there will be no significant impact on the consolidated financial statements.

- The new impairment model requires the recognition of impairment provisions based on expected credit losses ("ECL") rather than only incurred credit losses as is the case under IAS 39. The Company reviewed its portfolio of financial assets subject to the new model of impairment under the new methodology (using credit default swaps, rating from credit agencies and other external inputs in order to estimate the probability of default), and concluded that initial impact on the consolidated financial statements is not significant.

- The accounting for certain modifications and exchanges of financial liabilities measured at amortized cost (e.g. bank loans and issued bonds) will change on the transition from IAS 39 to IFRS 9. This change arises from a clarification by the IASB in the Basis for Conclusions of IFRS 9. Under IFRS 9 it is now clear that there can be an effect in the income statement for modification and exchanges of financial liabilities that are considered “non-substantial” (when the net present value of the cash flows, including any fees paid net of any fees received, is lower than 10% different from the net present value of the remaining cash flows of the liability prior to the modification, both discounted at the original effective interest rate). The Company reviewed retrospectively these transactions and concluded that the impact is not significant.

- IFRS 9 also introduces changes in hedge accounting. The hedge accounting requirements in IFRS 9 are optional and tend to facilitate the use of hedge accounting by preparers of financial statements. As a result, the Company reviewed its portfolio of derivatives and concluded that there will not be significant impact on its consolidated financial statements as a result of applying IFRS 9.

- The new standard will require some new disclosures, in particular regarding hedge accounting, credit risk and ECLs that will be presented in future periods.

IFRS 16 ‘Leases’

The IASB issued a new lease accounting standard, IFRS 16, in January 2016, which will require the recognition of lease contracts on the consolidated statement of financial position.

IFRS 16 eliminates the classification of leases as either operating leases or finance leases for a lessee. Instead all leases are treated in a similar way to finance leases applying IAS 17. Leases are ‘capitalized’ by recognizing the present value of the lease payments and showing them either as lease assets (right-of-use of assets) or together with property, plant and equipment. If lease payments are made over time, a company also recognizes a financial liability representing its obligation to make future lease payments.

In the income statement, IFRS 16 replaces the straight-line operating lease expense for those leases applying IAS 17, with a depreciation charge for the lease asset (included within operating expenses) and an interest expense on the lease liability (included within finance expenses). IFRS 16 will also have an effect on the presentation of cash flows related to former off-balance sheet leases.

The Company performed its assessment of the impact on its consolidated financial statements. The most significant impact identified is that the Company will recognize new assets and liabilities for its existing operating leases of land rights, buildings, offices and equipment.

The standard is effective for annual periods beginning on or after January 1, 2019, with earlier application permitted for entities that apply IFRS 15 at or before the date of initial application of IFRS 16. The Company decided to early adopt the standard as of January 1, 2018.

An entity shall apply this standard using one of the following two methods: full retrospectively approach or a modified retrospective approach. The Company has chosen the latter and will account for assets as an amount equal to liability at the date of initial application. The Company estimates the impact on the consolidated statement of financial position as of January 1, 2018, is not significant (less than 1% of total assets).

2.2. Principles to include and record companies in the consolidated financial statements

Companies included in these consolidated financial statements are accounted for as subsidiaries as long as Atlantica Yield has had control over them and are accounted for as investments under the equity method as long as Atlantica Yield has had significant influence over them, in the periods presented.

a) Controlled entities

Control is achieved when the Company:

· Has power over the investee;

· Is exposed, or has rights, to variable returns from its involvement with the investee; and

· Has the ability to use its power to affect its returns.

The Company reassesses whether or not it controls an investee when facts and circumstances indicate that there are changes to one or more of the three elements of control listed above.

The Company uses the acquisition method to account for business combinations of companies controlled by a third party. According to this method, identifiable assets acquired and liabilities and contingent liabilities assumed in a business combination are measured initially at their fair values at the acquisition date. Any contingent consideration is recognized at fair value at the acquisition date and subsequent changes in its fair value are recognized in accordance with IAS 39 either in profit or loss or as a change to other comprehensive income. Acquisition related costs are expensed as incurred. The Company recognizes any non-controlling interest in the acquiree either at fair value or at the non-controlling interest's proportionate share of the acquirer's net assets on an acquisition by acquisition basis.

Acquisitions of businesses from Abengoa were until December 31, 2015, not considered business combinations, as Atlantica Yield was a subsidiary controlled by Abengoa. The assets acquired constituted an acquisition under common control by Abengoa and accordingly, were recorded using Abengoa's historical basis in the assets and liabilities of the Predecessor. Abengoa has no control over the Company since December 31, 2015. Therefore, any purchase from Abengoa is accounted for in the consolidated accounts of Atlantica Yield since December 31, 2015, in accordance with IFRS 3, Business Combination.

All assets and liabilities between entities of the group, equity, income, expenses, and cash flows relating to transactions between entities of the group are eliminated in full.

b) Investments accounted for under the equity method

An associate is an entity over which the Company has significant influence. Significant influence is the power to participate in the financial and operating policy decisions of the investee but is not control or joint control over those policies.

The results and assets and liabilities of associates are incorporated in these financial statements using the equity method of accounting. Under the equity method, an investment in an associate is initially recognized in the statement of financial position at cost and adjusted thereafter to recognize the Company share of the profit or loss and other comprehensive income of the associate.

Controlled entities and associates included in these financial statements as of December 31, 2017 and 2016 are set out in appendices.

2.3. Contracted concessional assets and price purchase agreements

Contracted concessional assets and price purchase agreements (PPAs) include fixed assets financed through project debt, related to service concession arrangements recorded in accordance with IFRIC 12, except for Palmucho, which is recorded in accordance with IAS 17 and PS10, PS20 and Seville PV, which are recorded as tangible assets in accordance with IAS 16. The infrastructures accounted for by the Company as concessions are related to the activities concerning electric transmission lines, solar electricity generation plants, cogeneration plants, wind farms and water plants. The useful life of these assets is approximately the same as the length of the concession arrangement. The infrastructure used in a concession can be classified as an intangible asset or a financial asset, depending on the nature of the payment entitlements established in the agreement.

The application of IFRIC 12 requires extensive judgment in relation with, among other factors, (i) the identification of certain infrastructures and contractual agreements in the scope of IFRIC 12, (ii) the understanding of the nature of the payments in order to determine the classification of the infrastructure as a financial asset or as an intangible asset and (iii) the timing and recognition of the revenue from construction and concessionary activity.

Under the terms of contractual arrangements within the scope of this interpretation, the operator shall recognize and measure revenue in accordance with IAS 11 and 18 for the services it performs. If the operator performs more than one service (i.e. construction or upgrade services and operation services) under a single contract or arrangement, consideration received or receivable shall be allocated by reference to the relative fair values of the services delivered, when the amounts are separately identifiable.

a) Intangible asset

The Company recognizes an intangible asset to the extent that it receives a right to charge final customers for the use of the infrastructure. This intangible asset is subject to the provisions of IAS 38 and is amortized linearly, taking into account the estimated period of commercial operation of the infrastructure which coincides with the concession period.

Once the infrastructure is in operation, the treatment of income and expenses is as follows:

- Revenues from the updated annual revenue for the contracted concession, as well as operations and maintenance services are recognized in each period according to IAS 18 “Revenue”.

- Operating and maintenance costs and general overheads and administrative costs are recorded in accordance with the nature of the cost incurred (amount due) in each period.

- Financing costs are expensed as incurred.

b) Financial asset

The Company recognizes a financial asset when demand risk is assumed by the grantor, to the extent that the concession holder has an unconditional right to receive payments for the asset. This asset is recognized at the fair value of the construction services provided, considering upgrade services in accordance with IAS 11, if any.

The financial asset is subsequently recorded at amortized cost calculated according to the effective interest method. Revenue from operations and maintenance services is recognized in each period according to IAS 18 “Revenue”. The remuneration of managing and operating the asset resulting from the valuation at amortized cost is also recorded in revenue.

Financing costs are expensed as incurred.

c) Property, plant and equipment

Property, plant and equipment includes property, plant and equipment of companies or project companies. Property, plant and equipment is measured at historical cost, including all expenses directly attributable to the acquisition, less depreciation and impairment losses, with the exception of land, which is presented net of any impairment losses.

Once the infrastructure is in operation, the treatment of income and expenses is the same as the one described above for intangible asset.

2.4. Borrowing costs

Interest costs incurred in the construction of any qualifying asset are capitalized over the period required to complete and prepare the asset for its intended use. A qualifying asset is an asset that necessarily takes a substantial period of time to get ready for its internal use or sale, which is considered to be more than one year. Remaining borrowing costs are expensed in the period in which they are incurred.

2.5 Asset impairment

Atlantica Yield reviews its contracted concessional assets to identify any indicators of impairment at least annually.

The recoverable amount of an asset is the higher of its fair value less costs to sell and its value in use, defined as the present value of the estimated future cash flows to be generated by the asset. In the event that the asset does not generate cash flows independently of other assets, the Company calculates the recoverable amount of the Cash Generating Unit ('CGU') to which the asset belongs.

When the carrying amount of the CGU to which these assets belong is higher than its recoverable amount, the assets are impaired.

Assumptions used to calculate value in use include a discount rate, growth rate and projections considering real data based in the contracts terms and projected changes in both selling prices and costs. The discount rate is estimated by Management, to reflect both changes in the value of money over time and the risks associated with the specific CGU.

For contracted concessional assets, with a defined useful life and with a specific financial structure, cash flow projections until the end of the project are considered and no terminal value is assumed.

Contracted concessional assets have a contractual structure that permits the Company to estimate quite accurately the costs of the project (both in the construction and in the operations periods) and revenue during the life of the project.

Projections take into account real data based on the contract terms and fundamental assumptions based on specific reports prepared by experts, assumptions on demand and assumptions on production. Additionally, assumptions on macro-economic conditions are taken into account, such as inflation rates, future interest rates, etc. and sensitivity analyses are performed over all major assumptions which can have a significant impact in the value of the asset.

Cash flow projections of CGUs are calculated in the functional currency of those CGUs and are discounted using rates that take into consideration the risk corresponding to each specific country and currency.

Taking into account that in most CGUs the specific financial structure is linked to the financial structure of the projects that are part of those CGUs, the discount rate used to calculate the present value of cash-flow projections is based on the weighted average cost of capital (WACC) for the type of asset, adjusted, if necessary, in accordance with the business of the specific activity and with the risk associated with the country where the project is performed.

In any case, sensitivity analyses are performed, especially in relation with the discount rate used and fair value changes in the main business variables, in order to ensure that possible changes in the estimates of these items do not impact the possible recovery of recognized assets.

Accordingly, the following table provides a summary of the discount rates used (WACC) and growth rates to calculate the recoverable amount for CGUs with the operating segment to which it pertains:

Operating segment	Discount rate	Growth rate
EMEA	4% - 6%	0%
North America	4% - 6%	0%
South America	5% - 7%	0%

In the event that the recoverable amount of an asset is lower than its carrying amount, an impairment charge for the difference would be recorded in the income statement under the item "Depreciation, amortization and impairment charges".

Pursuant to IAS 36, an impairment loss is recognized if the carrying amount of these assets exceeds the present value of future cash flows discounted at the initial effective interest rate.

2.6 Loans and accounts receivable

Loans and accounts receivable are non-derivative financial assets with fixed or determinable payments, not listed on an active market.

In accordance with IFRIC 12, certain assets under concessions qualify as financial assets and are recorded as is described in Note 2.3.

Pursuant to IAS 36, an impairment loss is recognized if the carrying amount of these assets exceeds the present value of future cash flows discounted at the initial effective interest rate.

Loans and accounts receivable are initially recognized at fair value plus transaction costs and are subsequently measured at amortized cost in accordance with the effective interest rate method. Interest calculated using the effective interest rate method is recognized under other financial income within financial income.

2.7. Derivative financial instruments and hedging activities

Derivatives are recorded at fair value. The Company applies hedge accounting to all hedging derivatives that qualify to be accounted for as hedges under IFRS-IASB.

When hedge accounting is applied, hedging strategy and risk management objectives are documented at inception, as well as the relationship between hedging instruments and hedged items. Effectiveness of the hedging relationship needs to be assessed on an ongoing basis. Effectiveness tests are performed prospectively and retrospectively at inception and at each reporting date, following the dollar offset method or the regression method, depending on the type of derivatives and the type of tests performed.

Atlantica Yield applies cash flow hedging. Under this method, the effective portion of changes in fair value of derivatives designated as cash flow hedges are recorded temporarily in equity and are subsequently reclassified from equity to profit or loss in the same period or periods during which the hedged item affects profit or loss. Any ineffective portion of the hedged transaction is recorded in the consolidated income statement as it occurs.

When interest rate options are designated as hedging instruments, the intrinsic value and time value of the financial hedge instrument are separated. Changes in intrinsic value which are highly effective are recorded in equity and subsequently reclassified from equity to profit or loss in the same period or periods during which the hedged item affects profit or loss. Changes in time value are recorded as financial income or expense, together with any ineffectiveness.

When the hedging instrument matures or is sold, or when it no longer meets the requirements to apply hedge accounting, accumulated gains and losses recorded in equity remain as such until the forecast transaction is ultimately recognized in the income statement. However, if it becomes unlikely that the forecast transaction will actually take place, the accumulated gains and losses in equity are recognized immediately in the income statement.

2.8. Fair value estimates

Financial instruments measured at fair value are presented in accordance with the following level classification based on the nature of the inputs used for the calculation of fair value:

- Level 1: Inputs are quoted prices in active markets for identical assets or liabilities.
- Level 2: Fair value is measured based on inputs other than quoted prices included within Level 1 that are observable for the asset or liability, either directly (i.e. as prices) or indirectly (i.e. derived from prices).

- Level 3: Fair value is measured based on unobservable inputs for the asset or liability.

In the event that prices cannot be observed, the management shall make its best estimate of the price that the market would otherwise establish based on proprietary internal models which, in the majority of cases, use data based on observable market parameters as significant inputs (Level 2) but occasionally use market data that is not observed as significant inputs (Level 3). Different techniques can be used to make this estimate, including extrapolation of observable market data. The best indication of the initial fair value of a financial instrument is the price of the transaction, except when the value of the instrument can be obtained from other transactions carried out in the market with the same or similar instruments, or valued using a valuation technique in which the variables used only include observable market data, mainly interest rates. Differences between the transaction price and the fair value based on valuation techniques that use data that is not observed in the market, are not initially recognized in the income statement.

Atlantica Yield derivatives correspond primarily to the interest rate swaps designated as cash flow hedges, which are classified as Level 2:

Description of the valuation method

Interest rate swap valuations are made by valuing the swap part of the contract and valuing the credit risk. The methodology used by the market and applied by Atlantica Yield to value interest rate swaps is to discount the expected future cash flows according to the parameters of the contract. Variable interest rates, which are needed to estimate future cash flows, are calculated using the curve for the corresponding currency and extracting the implicit rates for each of the reference dates in the contract. These estimated flows are discounted with the swap zero curve for the reference period of the contract.

The effect of the credit risk on the valuation of the interest rate swaps depends on the future settlement. If the settlement is favorable for the Company, the counterparty credit spread will be incorporated to quantify the probability of default at maturity. If the expected settlement is negative for the Company, its own credit risk will be applied to the final settlement.

Classic models for valuing interest rate swaps use deterministic valuation of the future of variable rates, based on future outlooks. When quantifying credit risk, this model is limited by considering only the risk for the current paying party, ignoring the fact that the derivative could change sign at maturity. A payer and receiver swaption model is proposed for these cases. This enables the associated risk in each swap position to be reflected. Thus, the model shows each agent’s exposure, on each payment date, as the value of entering into the ‘tail’ of the swap, i.e. the live part of the swap.

Variables (Inputs)

Interest rate derivative valuation models use the corresponding interest rate curves for the relevant currency and underlying reference in order to estimate the future cash flows and to discount them. Market prices for deposits, futures contracts and interest rate swaps are used to construct these curves. Interest rate options (caps and floors) also use the volatility of the reference interest rate curve.

To estimate the credit risk of the counterparty, the credit default swap (CDS) spreads curve is obtained in the market for important individual issuers. For less liquid issuers, the spreads curve is estimated using comparable CDSs or based on the country curve. To estimate proprietary credit risk, prices of debt issues in the market and CDSs for the sector and geographic location are used.

The fair value of the financial instruments that results from the aforementioned internal models takes into account, among other factors, the terms and conditions of the contracts and observable market data, such as interest rates, credit risk and volatility. The valuation models do not include significant levels of subjectivity, since these methodologies can be adjusted and calibrated, as appropriate, using the internal calculation of fair value and subsequently compared to the corresponding actively traded price. However, valuation adjustments may be necessary when the listed market prices are not available for comparison purposes.

2.9. Clients and other receivables

Clients and other receivables are amounts due from customers for sales in the normal course of business. They are recognized initially at fair value and subsequently measured at amortized cost using the effective interest rate method, less allowance for doubtful accounts. Trade receivables due in less than one year are carried at their face value at both initial recognition and subsequent measurement, provided that the effect of not discounting flows is not significant.

An allowance for doubtful accounts is recorded when there is objective evidence that the Company will not be able to recover all amounts due as per the original terms of the receivables.

2.10. Cash and cash equivalents

Cash and cash equivalents include cash in hand, cash in bank and other highly-liquid current investments with an original maturity of three months or less which are held for the purpose of meeting short-term cash commitments.

2.11. Grants

Grants are recognized at fair value when it is considered that there is a reasonable assurance that the grant will be received and that the necessary qualifying conditions, as agreed with the entity assigning the grant, will be adequately complied with.

Grants are recorded as liabilities in the consolidated statement of financial position and are recognized in “Other operating income” in the consolidated income statement based on the period necessary to match them with the costs they intend to compensate.

In addition, as described in Note 2.12 below, grants correspond also to loans with interest rates below market rates, for the initial difference between the fair value of the loan and the proceeds received.

2.12. Loans and borrowings

Loans and borrowings are initially recognized at fair value, net of transaction costs incurred. Borrowings are subsequently measured at amortized cost and any difference between the proceeds initially received (net of transaction costs incurred in obtaining such proceeds) and the repayment value is recognized in the consolidated income statement over the duration of the borrowing using the effective interest rate method.

Loans with interest rates below market rates are initially recognized at fair value in liabilities and the difference between proceeds received from the loan and its fair value is initially recorded within “Grants and Other liabilities” in the consolidated statement of financial position, and subsequently recorded in “Other operating income” in the consolidated income statement when the costs financed with the loan are expensed.

2.13. Bonds and notes

The Company initially recognizes ordinary notes at fair value, net of issuance costs incurred. Subsequently, notes are measured at amortized cost until settlement upon maturity. Any other difference between the proceeds obtained (net of transaction costs) and the redemption value is recognized in the consolidated income statement over the term of the debt using the effective interest rate method.

2.14. Income taxes

Current income tax expense is calculated on the basis of the tax laws in force as of the date of the consolidated statement of financial position in the countries in which the subsidiaries and associates operate and generate taxable income.

Deferred income tax is calculated in accordance with the liability method, based upon the temporary differences arising between the carrying amount of assets and liabilities and their tax base. Deferred income tax is determined using tax rates and regulations which are expected to apply at the time when the deferred tax is realized.

Deferred tax assets are recognized only when it is probable that sufficient future taxable profit will be available to use deferred tax assets.

2.15. Trade payables and other liabilities

Trade payables are obligations arising from purchases of goods and services in the ordinary course of business and are recognized initially at fair value and are subsequently measured at their amortized cost using the effective interest method. Other liabilities are obligations not arising in the normal course of business and which are not treated as financing transactions. Advances received from customers are recognized as “Trade payables and other current liabilities”.

2.16. Foreign currency transactions

The consolidated financial statements are presented in U.S. dollars, which is Atlantica Yield functional and reporting currency. Financial statements of each subsidiary within the Company are measured in the currency of the principal economic environment in which the subsidiary operates, which is the subsidiary’s functional currency.

Transactions denominated in a currency different from the subsidiary’s functional currency are translated into the subsidiary’s functional currency applying the exchange rates in force at the time of the transactions. Foreign currency gains and losses that result from the settlement of these transactions and the translation of monetary assets and liabilities denominated in foreign currency at the year-end rates are recognized in the consolidated income statement, unless they are deferred in equity, as occurs with cash flow hedges and net investment in foreign operations hedges.

Assets and liabilities of subsidiaries with a functional currency different from the Company’s reporting currency are translated to U.S. dollars at the exchange rate in force at the closing date of the financial statements. Income and expenses are translated into U.S. dollars using the average annual exchange rate, which does not differ significantly from using the exchange rates of the dates of each transaction. The difference between equity translated at the historical exchange rate and the net financial position that results from translating the assets and liabilities at the closing rate is recorded in equity under the heading “Accumulated currency translation differences”.

Results of companies carried under the equity method are translated at the average annual exchange rate.

2.17. Equity

The Company has recyclable balances in its equity, corresponding mainly to hedge reserves and translation differences arising from currency conversion in the preparation of these consolidated financial statements. These balances have been presented separately in Equity.

Non-controlling interest represents interest from other partners in entities included in these consolidated financial statements which are not fully owned by Atlantica Yield as of the dates presented.

Parent company reserves together with the Share capital represent the Parent’s net investment in the entities included in these consolidated financial statements.

2.18. Provisions and contingencies

Provisions are recognized when:

- there is a present obligation, either legal or constructive, as a result of past events;
- it is more likely than not that there will be a future outflow of resources to settle the obligation; and
- the amount has been reliably estimated.

Provisions are initially measured at the present value of the expected outflows required to settle the obligation and subsequently valued at amortized cost following the effective interest method. The balance of Provisions disclosed in the Notes reflects management's best estimate of the potential exposure as of the date of preparation of the consolidated financial statements.

Contingent liabilities are possible obligations, existing obligations with low probability of a future outflow of economic resources and existing obligations where the future outflow cannot be reliably estimated. Contingences are not recognized in the consolidated statements of financial position unless they have been acquired in a business combination.

Some companies included in the group have dismantling provisions, which are intended to cover future expenditures related to the dismantlement of the plants and it will be likely to be settled with an outflow of resources in the long term (over 5 years).

Such provisions are accrued when the obligation for dismantling, removing and restoring the site on which the plant is located, is incurred, which is usually during the construction period. The provision is measured in accordance with IAS 37, "Provisions, Contingent Liabilities and Contingent Assets" and is recorded as a liability under the heading "Grants and other liabilities" of the Financial Statements, and as part of the cost of the plant under the heading "Contracted concessional assets."

2.19. Use of estimates

Some of the accounting policies applied require the application of significant judgment by management to select the appropriate assumptions to determine these estimates. These assumptions and estimates are based on the historical experience, advice from experienced consultants, forecasts and other circumstances and expectations as of the close of the financial period. The assessment is considered in relation to the global economic situation of the industries and regions where the Company operates, taking into account future development of the businesses of the Company. By their nature, these judgments are subject to an inherent degree of uncertainty; therefore, actual results could materially differ from the estimates and assumptions used. In such cases, the carrying values of assets and liabilities are adjusted.

The most critical accounting policies, which reflect significant management estimates and judgment to determine amounts in these consolidated financial statements, are as follows:

- Contracted concessional agreements and PPAs.
- Impairment of intangible assets and property, plant and equipment.
- Assessment of control.
- Derivative financial instruments and fair value estimates.
- Income taxes and recoverable amount of deferred tax assets.

As of the date of preparation of these consolidated financial statements, no relevant changes in the estimates made are anticipated and, therefore, no significant changes in the value of the assets and liabilities recognized at December 31, 2017, are expected.

Although these estimates and assumptions are being made using all available facts and circumstances, it is possible that future events may require management to amend such estimates and assumptions in future periods. Changes in accounting estimates are recognized prospectively, in accordance with IAS 8, in the consolidated income statement of the year in which the change occurs.

Note 3.- Financial risk management

Atlantica Yield’s activities are exposed to various financial risks: market risk (including currency risk and interest rate risk), credit risk and liquidity risk. Risk is managed by the Company’s Risk Finance and Compliance Departments, which are responsible for identifying and evaluating financial risks quantifying them by project, region and company, in accordance with mandatory internal management rules. Written internal policies exist for global risk management, as well as for specific areas of risk. In addition, there are official written management regulations regarding key controls and control procedures for each company and the implementation of these controls is monitored through internal audit procedures.

a) Market risk

The Company is exposed to market risk, such as movement in foreign exchange rates and interest rates. All of these market risks arise in the normal course of business and the Company does not carry out speculative operations. For the purpose of managing these risks, the Company uses a series of interest rate swaps and options, and currency options. None of the derivative contracts signed has an unlimited loss exposure.

- Interest rate risk

Interest rate risk arises when the Company’s activities are exposed to changes in interest rates, which arises from financial liabilities at variable interest rates. The main interest rate exposure for the Company relates to the variable interest rate with reference to the Libor and Euribor. To minimize the interest rate risk, the Company primarily uses interest rate swaps and interest rate options (caps), which, in exchange for a fee, offer protection against an increase in interest rates. The Company does not use derivatives for speculative purposes.

As a result, the notional amounts hedged, strikes contracted and maturities, depending on the characteristics of the debt on which the interest rate risk is being hedged, are very diverse, including the following:

- Project debt in Euros: the Company hedges between 87% and 100% of the notional amount, maturities until 2030 and average guaranteed interest rates of between 3.20% and 4.87%.

- Project debt in U.S. dollars: the Company hedges between 70% and 100% of the notional amount, including maturities until 2032 and average guaranteed interest rates of between 2.32% and 5.27%.

In connection with the interest rate derivative positions of the Company, the most significant impacts on these consolidated financial statements are derived from the changes in EURIBOR or LIBOR, which represent the reference interest rate for the majority of the debt of the Company. In the event that Euribor and Libor had risen by 25 basis points as of December 31, 2017, with the rest of the variables remaining constant, the effect in the consolidated income statement would have been a loss of $228 thousand (a loss of $2,563 thousand in 2016 and a loss of $1,795 thousand in 2015) and an increase in hedging reserves of $37,767 thousand ($37,290 thousand in 2016 and $41,702 thousand in 2015). The increase in hedging reserves would be mainly due to an increase in the fair value of interest rate swaps designated as hedges.

A breakdown of the interest rates derivatives as of December 31, 2017 and 2016, is provided in Note 9.

- Currency risk

The main cash flows in the entities included in these consolidated financial statements are cash collections arising from long-term contracts with clients and debt payments arising from project finance repayment. Given that financing of the projects is always closed in the same currency in which the contract with client is signed, a natural hedge exists for the main operations of the Company.

In addition, the Company policy is to contract currency options with leading financial institutions, which guarantee a minimum Euro-U.S. dollar exchange rate on the net distributions expected from Spanish solar assets. The net Euro exposure is 100% covered for the coming 12 months and 75% for the following 12 months on a rolling basis.

b) Credit risk

The Company considers that it has a limited credit risk with clients as revenues derive from power purchase agreements with electric utilities and state-owned entities. The Company has investment grade offtakers in all the assets except for Quadra 1&2, ATN2, Skikda and Honaine, which represent a low percentage of the cash available for distribution on a run-rate basis. In the case of Kaxu, the offtaker has a counter-guarantee from the Republic of South Africa.

c) Liquidity risk

Atlantica Yield’s liquidity and financing policy is intended to ensure that the Company maintains sufficient funds to meet our financial obligations as they fall due.

Project finance borrowing permits the Company to finance the project through project debt and thereby insulate the rest of its assets from such credit exposure. The Company incurs in project-finance debt on a project-by-project basis.

The repayment profile of each project is established on the basis of the projected cash flow generation of the business. This ensures that sufficient financing is available to meet deadlines and maturities, which mitigates the liquidity risk significantly.

Note 4.- Financial information by segment

Atlantica Yield’s segment structure reflects how management currently makes financial decisions and allocates resources. Its operating and reportable segments are based on the following geographies where the contracted concessional assets are located:

- North America
- South America
- EMEA

Based on the type of business, as of December 31, 2017 the Company had the following business sectors:

Renewable energy: Renewable energy assets include two solar plants in the United States, Solana and Mojave, each with a gross capacity of 280 MW and located in Arizona and California, respectively. The Company owns eight solar platforms in Spain: Solacor 1 and 2 with a gross capacity of 100 MW, PS10 and PS20 with a gross capacity of 31 MW, Solaben 2 and 3 with a gross capacity of 100 MW, Helioenergy 1 and 2 with a gross capacity of 100 MW, Helios 1 and 2 with a gross capacity of 100 MW, Solnova 1, 3 and 4 with a gross capacity of 150 MW, Solaben 1 and 6 with a gross capacity of 100 MW and Seville PV with a gross capacity of 1 MW. The Company also owns a solar plant in South Africa, Kaxu with a gross capacity of 100 MW. Additionally, the Company owns two wind farms in Uruguay, Palmatir and Cadonal, with a gross capacity of 50 MW each.

Efficient natural gas: The Company´s sole efficient natural gas asset is ACT, a 300 MW cogeneration plant in Mexico, which is party to a 20-year take-or-pay contract with Pemex for the sale of electric power and steam.

Electric transmission lines: Electric transmission assets include (i) three lines in Peru, ATN, ATS and ATN2, spanning a total of 1,012 miles; and (ii) three lines in Chile, Quadra 1, Quadra 2 and Palmucho, spanning a total of 87 miles.

Water: Water assets include a minority interest in two desalination plants in Algeria, Honaine and Skikda with an aggregate capacity of 10.5 M ft^3 per day.

Atlantica Yield’s Chief Operating Decision Maker (CODM) assesses the performance and assignment of resources according to the identified operating segments. The CODM considers the revenues as a measure of the business activity and the Further Adjusted EBITDA as a measure of the performance of each segment. Further Adjusted EBITDA is calculated as profit/(loss) for the period attributable to the parent company, after adding back loss/(profit) attributable to non-controlling interests from continued operations, income tax, share of profit/(loss) of associates carried under the equity method, finance expense net, depreciation, amortization and impairment charges of entities included in these consolidated financial statements, and dividends received from the preferred equity investment in ACBH. Further adjusted EBITDA for 2016 and 2017 includes compensation received from Abengoa in lieu of ACBH dividends.

In order to assess performance of the business, the CODM receives reports of each reportable segment using revenues and Further Adjusted EBITDA. Net interest expense evolution is assessed on a consolidated basis. Financial expense and amortization are not taken into consideration by the CODM for the allocation of resources.

In the years ended December 31, 2017 and December 31, 2016, Atlantica Yield had three customers with revenues representing more than 10% of the total revenues, i.e., two in the renewable energy and one in the efficient natural gas business sectors.

a) The following tables show Revenues and Further Adjusted EBITDA by operating segments and business sectors for the years 2017, 2016 and 2015:

	Revenue			Further Adjusted EBITDA		
	For the year ended December 31,			For the year ended December 31,		
Geography	**2017**	**2016**	**2015**	**2017**	**2016**	**2015**
North America	$ 332,705	$ 337,061	$ 328,139	$ 282,328	$ 284,691	$ 279,559
South America	120,797	118,764	112,480	108,766	124,599	110,905
EMEA	554,879	515,972	350,262	388,216	354,020	233,754
Total	**$ 1,008,381**	**$ 971,797**	**$ 790,881**	**$ 779,310**	**$ 763,310**	**$ 624,218**

	Revenue			Further Adjusted EBITDA		
	For the year ended December 31,			For the year ended December 31,		
Business sectors	**2017**	**2016**	**2015**	**2017**	**2016**	**2015**
Renewable energy	$ 767,226	$ 724,325	$ 543,012	$ 569,193	$ 538,427	$ 413,933
Efficient natural gas	119,784	128,046	138,717	106,140	106,492	107,671
Electric transmission lines	95,096	95,137	86,393	87,695	104,795	89,047
Water	26,275	24,288	22,759	16,282	13,596	13,567
Total	**$ 1,008,381**	**$ 971,797**	**$ 790,881**	**$ 779,310**	**$ 763,310**	**$ 624,218**

The reconciliation of segment Further Adjusted EBITDA with the profit/(loss) attributable to the parent company is as follows:

	For the year ended December 31,		
	2017	**2016**	**2015**
Loss attributable to the Company	$ (111,804)	$ (4,855)	$ (209,005)
Profit attributable to non-controlling interests	6,917	6,522	10,819
Income tax	119,837	1,666	23,790
Share of profits/(losses) of associates	(5,351)	(6,646)	(7,844)
Dividend from exchangeable preferred equity investment in ACBH (Note 21)	10,383	27,948	18,400
Financial expense, net	448,368	405,750	526,758
Depreciation, amortization, and impairment charges	310,960	332,925	261,301
Total segment Further Adjusted EBITDA	**$ 779,310**	**$ 763,310**	**$ 624,219**

b) The assets and liabilities by operating segments (and business sector) at the end of 2017 and 2016 are as follows:

Assets and liabilities by geography as of December 31, 2017:

	North America	South America	EMEA	Balance as of December 31, 2017
Assets allocated				
Contracted concessional assets	3,770,169	1,100,778	4,213,323	9,084,270
Investments carried under the equity method	-	-	55,784	55,784
Current financial investments	116,451	59,831	31,263	207,545
Cash and cash equivalents (project companies)	149,236	42,548	329,078	520,862
Subtotal allocated	**4,035,856**	**1,203,157**	**4,629,448**	**9,868,461**
Unallocated assets				
Other non-current assets				210,378
Other current assets (including cash and cash equivalents at holding company level)				413,500
Subtotal unallocated				**623,878**
Total assets				**10,492,339**

	North America	South America	EMEA	Balance as of December 31, 2017
Liabilities allocated				
Long-term and short-term project debt	1,821,102	876,063	2,778,043	5,475,208
Grants and other liabilities	1,593,048	810	42,202	1,636,060
Subtotal allocated	**3,414,150**	**876,873**	**2,820,245**	**7,111,268**
Unallocated liabilities				
Long-term and short-term corporate debt				643,083
Other non-current liabilities				657,345
Other current liabilities				185,190
Subtotal unallocated				**1,485,618**
Total liabilities				**8,596,886**
Equity unallocated				**1,895,453**
Total liabilities and equity unallocated				**3,381,071**
Total liabilities and equity				**10,492,339**

Assets and liabilities by geography as of December 31, 2016:

	North America	South America	EMEA	Balance as of December 31, 2016
Assets allocated				
Contracted concessional assets	3,920,106	1,144,712	3,859,454	8,924,272
Investments carried under the equity method	-	-	55,009	55,009
Current financial investments	136,665	62,215	29,158	228,038
Cash and cash equivalents (project companies)	185,970	40,015	246,671	472,656
Subtotal allocated	**4,242,741**	**1,246,942**	**4,190,291**	**9,679,975**
Unallocated assets				
Other non-current assets				272,664
Other current assets (including cash and cash equivalents at holding company level)				345,160
Subtotal unallocated				**617,824**
Total assets				**10,297,799**

	North America	South America	EMEA	Balance as of December 31, 2016
Liabilities allocated				
Long-term and short-term project debt	1,870,861	895,316	2,564,290	5,330,467
Grants and other liabilities	1,575,303	1,512	35,230	1,612,045
Subtotal allocated	**3,446,164**	**896,828**	**2,599,520**	**6,942,512**
Unallocated liabilities				
Long-term and short-term corporate debt				668,201
Other non-current liabilities				546,053
Other current liabilities				181,922
Subtotal unallocated				**1,396,176**
Total liabilities				**8,338,688**
Equity unallocated				**1,959,111**
Total liabilities and equity unallocated				**3,355,287**
Total liabilities and equity				**10,297,799**

Assets and liabilities by business sectors as of December 31, 2017:

	Renewable energy	Efficient natural gas	Electric transmission lines	Water	Balance as of December 31, 2017
Assets allocated					
Contracted concessional assets	7,436,362	660,387	897,269	90,252	9,084,270
Investments carried under the equity method	12,419	-	-	43,365	55,784
Current financial investments	17,249	116,430	59,289	14,577	207,545
Cash and cash equivalents (project companies)	452,792	39,064	15,325	13,681	520,862
Subtotal allocated	**7,918,822**	**815,881**	**971,883**	**161,875**	**9,868,461**
Unallocated assets					
Other non-current assets					210,378
Other current assets (including cash and cash equivalents at holding company level)					413,500
Subtotal unallocated					**623,878**
Total assets					**10,492,339**

	Renewable energy	Efficient natural gas	Electric transmission lines	Water	Balance as of December 31, 2017
Liabilities allocated					
Long-term and short-term project debt	4,162,596	579,173	698,346	35,093	5,475,208
Grants and other liabilities	1,635,508	552	-	-	1,636,060
Subtotal allocated	**5,798,104**	**579,725**	**698,346**	**35,093**	**7,111,268**
Unallocated liabilities					
Long-term and short-term corporate debt					643,083
Other non-current liabilities					657,345
Other current liabilities					185,190
Subtotal unallocated					**1,485,618**
Total liabilities					**8,596,886**
Equity unallocated					**1,895,453**
Total liabilities and equity unallocated					**3,381,071**
Total liabilities and equity					**10,492,339**

Assets and liabilities by business sectors as of December 31, 2016:

	Renewable energy	Efficient natural gas	Electric transmission lines	Water	Balance as of December 31, 2016
Assets allocated					
Contracted concessional assets	7,255,308	646,927	929,005	93,032	8,924,272
Investments carried under the equity method	12,953	-	-	42,056	55,009
Current financial investments	13,661	136,644	62,215	15,518	228,038
Cash and cash equivalents (project companies)	420,215	30,295	11,357	10,789	472,656
Subtotal allocated	**7,702,137**	**813,866**	**1,002,577**	**161,395**	**9,679,975**
Unallocated assets					
Other non-current assets					272,664
Other current assets (including cash and cash equivalents at holding company level)					345,160
Subtotal unallocated					**617,824**
Total assets					**10,297,799**

	Renewable energy	Efficient natural gas	Electric transmission lines	Water	Balance as of December 31, 2016
Liabilities allocated					
Long-term and short-term project debt	3,979,096	598,256	711,517	41,598	5,330,467
Grants and other liabilities	1,611,067	239	739	-	1,612,045
Subtotal allocated	**5,590,163**	**598,495**	**712,256**	**41,598**	**6,942,512**
Unallocated liabilities					
Long-term and short-term corporate debt					668,201
Other non-current liabilities					546,053
Other current liabilities					181,922
Subtotal unallocated					**1,396,176**
Total liabilities					**8,338,688**
Equity unallocated					**1,959,111**
Total liabilities and equity unallocated					**3,355,287**
Total liabilities and equity					**10,297,799**

c) The amount of depreciation, amortization and impairment charges recognized for the years ended December 31, 2017, 2016 and 2015 are as follows:

	For the year ended December 31,		
Depreciation, amortization and impairment by geography	**2017**	**2016**	**2015**
North America	(123,726)	(129,478)	(129,091)
South America	(40,880)	(62,387)	(41,274)
EMEA	(146,354)	(141,060)	(90,936)
Total	**(310,960)**	**(332,925)**	**(261,301)**

	For the year ended December 31,		
Depreciation, amortization and impairment by business sectors	**2017**	**2016**	**2015**
Renewable energy	(282,376)	(304,235)	(232,699)
Electric transmission lines	(28,584)	(28,690)	(28,602)
Total	**(310,960)**	**(332,925)**	**(261,301)**

Note 5.- Changes in the scope of the consolidated financial statements

For the year ended December 31, 2017

There is no change in the scope of the consolidated financial statement in the year 2017.

For the year ended December 31, 2016

On January 7, 2016, the Company closed the acquisition of a 13% stake in Solacor 1/2 from JGC, which reduced JGC´s ownership in Solacor 1/2 to 13%. The total purchase price for these assets amounted to $19,923 thousand.

The difference between the amount of Non-Controlling interest representing the 13% interest held by JGC accounted for in the consolidated accounts at the purchase date, and the purchase price has been recorded in equity in these consolidated financial statements, pursuant to IFRS 10, Consolidated Financial Statements.

On August 3, 2016, the Company completed the acquisition of an 80% stake in Seville PV. Total purchase price paid for this asset amounted to $3,214 thousand. The purchase has been accounted for in the consolidated accounts of Atlantica Yield, in accordance with IFRS 3, Business Combinations.

Note 6.- Contracted concessional assets

Contracted concessional assets include fixed assets financed through project debt, related to service concession arrangements recorded in accordance with IFRIC 12, except for Palmucho, which is recorded in accordance with IAS 17, and PS10, PS20 and Seville PV which are recorded as property plant and equipment in accordance with IAS 16. Concessional assets recorded in accordance with IFRIC 12 are either intangible of financial assets. As of December 31, 2017, contracted concessional financial assets amount to $936,004 thousand ($928,720 thousand as of December 31, 2016).

For further details on the application of IFRIC 12 to projects, see Appendix III.

a) The following table shows the movements of contracted concessional assets included in the heading “Contracted Concessional assets” for 2017:

Cost

Total as of January 1, 2017	10,067,596
Additions	15,426
Subtractions	(42,500)
Translation differences	593,247
Total as of December 31, 2017	**10,633,769**

Accumulated amortization

Total as of January 1, 2017	(1,143,324)
Additions	(309,846)
Translation differences	(96,329)
Total accum. amort. as of December 31, 2017	(1,549,499)
Net balance at December 31, 2017	**9,084,270**

During 2017 contracted concessional assets increased primarily due to the effect of appreciation of the Euro against the U.S. dollar for the year ended December 31, 2017 compared to the year ended December 31, 2016, this effect has been partially compensated by the amortization charge for the year.

The decrease relates to the indemnity received from Abengoa by Solana in December 2017 further to Abengoa´s obligation as EPC Contractor (see Note 10).

No losses from impairment of contracted concessional assets were recorded during the year ended December 31, 2017.

The Company identified a triggering event of impairment for Solana as a result of the generation of the plant having been lower than expected during 2017 related to an incident with electric transformers which took place in July 2017. This project is within the Renewable energy sector and North America geography. The Company therefore performed an impairment test as of December 31, 2017, which resulted in the recoverable amount (value in use) exceeding the carrying amount of the asset by 7%. To determine the value in use of the asset, a specific discount rate has been used in each year considering changes in the debt/equity leverage ratio over the useful life of this project, resulting in the use of a range of discount rates between 4.7% and 5.0%.

An adverse change in the key assumptions which are individually used for the valuation would not lead to future impairment recognition; neither in case of a 5% decrease in generation over the entire remaining useful life (PPA) of the project nor in case of an increase of 50 basis points in the discount rate.

b) The following table shows the movements of contracted concessional assets included in the heading "Contracted Concessional assets" for 2016:

Cost	
Total as of January 1, 2016	10,126,023
Additions	6,346
Translation differences	(68,199)
Change in the scope of the consolidated financial statements	5,876
Reclassification and other movements	(2,450)
Total as of December 31, 2016	**10,067,596**
Accumulated amortization	
Total as of January 1, 2016	(825,126)
Additions	(332,925)
Change in the scope of the consolidated financial statements	(2,381)
Translation differences	17,108
Total accum. amort. as of December 31, 2016	(1,143,324)
Net balance at December 31, 2016	**8,924,272**

During 2016 contracted concessional assets decreased primarily due to the amortization charge for the year.

Considering the low level of wind resources recorded since COD in Palmatir and Cadonal projects and the uncertainty around such level in the future, the Company identified a triggering event of impairment during the year 2016 in compliance with IAS 36, Impairment of Assets. As a result, impairment tests have been performed resulting in the recording of an impairment loss of $17,229 thousand and $3,101 thousand for the Cadonal and Palmatir projects, respectively, as of December 31, 2016.

The impairment has been recorded within the line "Depreciation, amortization and impairment charges" of the consolidated income statement, decreasing the amount of "Contracted concessional assets" pertaining to the Renewable energy sector and South America geography. The recoverable amount considered is the value in use and amounts to $91,795 thousand and $123,912 thousand for Cadonal and Palmatir, respectively, as of December 31, 2016. A specific discount rate has been used in each year considering changes in the debt/equity leverage ratio over the useful life of this project, resulting in the use of a range of discount rates between 6.7% and 7.0% for both projects.

An adverse change in the key assumptions which are individually used for the valuation could lead to future impairment recognition; especially, a 5% decrease in generation over the entire remaining useful life (PPA) of the project would generate an additional impairment of approximately $5 million for Cadonal and $7 million for Palmatir. An increase of 50 basis points in the discount rate would lead to an additional impairment of approximately $3 million for Cadonal and $4 million for Palmatir.

In addition, the Company identified a triggering event of impairment for Solana as a result of the generation of the plant having been lower than expected during its first years of operation. This project pertains to the Renewable energy sector and North America geography. The Company therefore performed an impairment test as of December 31, 2016, which resulted in the recoverable amount (value in use) exceeding the carrying amount of the asset by 3%. To determine the value in use of the asset, a specific discount rate has been used in each year considering changes in the debt/equity leverage ratio over the useful life of this project, resulting in the use of a range of discount rates between 4.1% and 5.1%.

An adverse change in the key assumptions which are individually used for the valuation could lead to future impairment recognition; especially, a 5% decrease in generation over the entire remaining useful life (PPA) of the project would generate an impairment of approximately $40 million. An increase of 50 basis points in the discount rate would lead to an impairment of approximately $30 million.

Note 7.- Investments carried under the equity method

The table below shows the breakdown and the movement of the investments held in associates for 2017 and 2016:

Investments in associates	**2017**	**2016**
Initial balance	55,009	56,181
Share of (loss)/profit	5,351	6,646
Dividend distribution	(2,454)	(3,954)
Equity distribution	(549)	(3,099)
Currency translation differences	(1,573)	(765)
Final balance	**55,784**	**55,009**

There are no significant movement of the investments held in associates during the year 2017.

The tables below show a breakdown of stand-alone amounts of assets, revenues and profit and loss as well as other information of interest for the years 2017 and 2016 for the associated companies:

Company	**% Shares**	**Non-current assets**	**Current assets**	**Non-current liabilities**	**Current liabilities**	**Revenue**	**Operating profit/ (loss)**	**Net profit/ (loss)**	**Investment under the equity method**
Evacuación Valdecaballeros, S.L.	57.16	21,306	841	373	451	298	(708)	(730)	9,175
Myah Bahr Honaine, S.P.A. (*)	25.50	195,275	64,114	91,205	12,649	46,767	28,468	24,464	43,365
Pectonex, R.F. Proprietary Limited	50.00	3,904	-	-	2	-	(206)	(206)	3,244
Evacuación Villanueva del Rey, S.L	40.02	3,526	53	2,265	190	-	37	-	-
As of December 31, 2017		**240,011**	**65,008**	**93,843**	**13,292**	**47,065**	**27,591**	**23,528**	**55,784**

Company	% Shares	Non-current assets	Current assets	Non-current liabilities	Current liabilities	Revenue	Operating profit/ (loss)	Net profit/ (loss)	Investment under the equity method
Evacuación Valdecaballeros, S.L.	57.16	19,283	931	306	532	537	(545)	(565)	9,528
Myah Bahr Honaine, S.P.A. (*)	25.50	202,150	67,120	104,704	14,158	52,770	34,247	29,990	42,056
Pectonex, R.F. Proprietary Limited	50.00	3,730	-	-	1	-	(187)	(187)	3,425
Evacuación Villanueva del Rey, S.L	40.02	3,251	17	2,118	142	-	31	-	-
As of December 31, 2016		**228,684**	**68,068**	**107,128**	**14,833**	**53,307**	**33,546**	**29,238**	**55,009**

The Company has no control over Evacuación Valdecaballeros, S.L. as all relevant decisions of this company require the approval of a minimum of shareholders accounting for more than 75% of the shares.

None of the associated companies referred to above is a listed company.

(*) Myah Bahr Honaine, S.P.A., the project entity, is 51% owned by Geida Tlemcen, S.L. which is accounted for using the equity method in these consolidated financial statements. Share of profit of Myah Bahr Honaine S.P.A. included in these consolidated financial statements amounts to $6,238 thousand in 2017 and $7,647 thousand in 2016.

Note 8.- Financial instruments by category

Financial instruments are primarily deposits, derivatives, trade and other receivables and loans. Financial instruments by category (current and non-current), reconciled with the statement of financial position as of December 31, 2017 and 2016 are as follows:

	Notes	Loans and receivables / payables	Available for sale financial assets	Hedging derivatives	Balance as of December 31, 2017
Derivative assets	9	-	-	8,230	8,230
Investment in Ten West Link		2,088	-	-	2,088
Abengoa debt and Equity instruments		-	1,715	-	1,715
Other financial investments		243,347	-	-	243,347
Clients and other receivables	11	244,449	-	-	244,449
Cash and cash equivalents	12	669,387	-	-	669,387
Total financial assets		**1,159,271**	**1,715**	**8,230**	**1,169,216**
Corporate debt	14	643,083	-	-	643,083
Project debt	15	5,475,208	-	-	5,475,208
Related parties – non-current	10	141,031	-	-	141,031
Trade and other current liabilities	17	155,144	-	-	155,144
Derivative liabilities	9	-	-	329,731	329,731
Total financial liabilities		**6,414,466**	-	**329,731**	**6,744,197**

	Notes	Loans and receivables / payables	Available for sale financial assets	Hedging derivatives	Balance as of December 31, 2016
Derivative assets	9	-	-	3,822	3,822
Preferred equity in ACBH		-	30,488	-	30,488
Other financial investments		263,501	-	-	263,501
Clients and other receivables	11	207,621	-	-	207,621
Cash and cash equivalents	12	594,811	-	-	594,811
Total financial assets		**1,065,933**	**30,488**	**3,822**	**1,100,243**
Corporate debt	14	668,201	-	-	668,201
Project debt	15	5,330,467	-	-	5,330,467
Related parties – non-current	10	101,750	-	-	101,750
Trade and other current liabilities	17	160,505	-	-	160,505
Derivative liabilities	9	-	-	349,266	349,266
Total financial liabilities		**6,260,923**	**-**	**349,266**	**6,610,189**

Further to the completion of a series of conditions precedent that made Abengoa´s restructuring effective as of March 31, 2017, the guarantee provided by Abengoa regarding the preferred equity investment in ACBH, which supported the fair value of this instrument of $30.5 million as of December 31, 2016, was canceled, which reduced the fair value of this instrument to nil. In exchange for the guarantee provided by Abengoa being canceled, the Company received a certain amount of equity in Abengoa, and Corporate tradable bonds issued by Abengoa and subject to a 5.5-year period stay (extendable to a 2 additional years subject further to the senior old money creditors´consent) and with a 1.5% annual interest rate (0.25% cash, 1.25% PIK).

Further to the restructuring agreement of Abengoa being made effective, the Company was assigned an amount of New Money 1 Tradable Notes of $44.5 million in exchange for contributing $43.6 million of cash. As a result of this contribution, the corporate tradable bonds detailed above are ranked as senior debt. The Company sold all the New Money 1 Tradable Notes it was assigned during the month of April 2017 for $44.9 million.

New Money 1 Tradable Notes assigned to Atlantica Yield, Corporate tradable bonds and shares in Abengoa received, together are further referred as “Abengoa Debt and Equity Instruments”. These are all available for sale financial assets, of which major part has been sold during the second, third and fourth quarter of 2017. The fair value of the remaining portion as of December 31, 2017 amounts to $1.7 million, and is classified as current financial investments.

Derecognition of the fair value assigned to the ACBH preferred equity investment and recognition of the Abengoa Debt and Equity Instruments resulted in a loss of $5.8 million. The sale of these instruments resulted in a profit of $6.5 million. Both impacts are accounted for in these consolidated financial statements for the year ended December 31, 2017 as Other net financial income and expenses (see Note 21).

Prior to Abengoa´s restructuring agreement being made effective, Abengoa acknowledged that it failed to fulfill its obligations under the agreements related to the preferred equity investment in ACBH and, as a result, Atlantica Yield is the legal owner of the dividends amounting to $10.4 million declared on February 24, 2017, that the Company retained from Abengoa. Upon receipt of Abengoa Debt and Equity Instruments, the Company waived its rights under the guarantee provided by Abengoa related to the ACBH agreements, including its right to retain the dividends payable to Abengoa.

Other financial investments include primarily the short-term portion of contracted concessional assets (see Note 6).

Investment in Ten West Link as of December 31, 201 is a $2.1 million investment, which was made by the Company accounting for a 12.5% interests in a 114-mile transmission line in the U.S.

As of December 31, 2017 and 2016, all the financial instruments measured at fair value have been classified as Level 2, except for the Abengoa Debt and Equity Instruments received further to the implementation of Abengoa´s restructuring agreement on March 31st 2017. The unsold portion as of December 31st 2017 is classified as Level 1.

Note 9.- Derivative financial instruments

The breakdowns of the fair value amount of the derivative financial instruments as of December 31, 2017 and 2016 are as follows:

	Balance as of December 31, 2017		Balance as of December 31, 2016	
	Assets	**Liabilities**	**Assets**	**Liabilities**
Derivatives - cash flow hedge	8,230	329,731	3,822	349,266

The derivatives are primarily interest rate cash-flow hedges. All are classified as non-current assets or non-current liabilities, as they hedge long-term financing agreements.

On May 12, 2015, the Company entered into a currency swap agreement with Abengoa which provided for a fixed exchange rate for the cash available for distribution from the Company's Spanish assets. The distributions from the Spanish assets are paid in euros and the currency swap agreement provided for a fixed exchange rate at which euros will be converted into U.S. dollars. The currency swap agreement had a five-year term, and was valued by comparing the contracted exchange rate and the future exchange rate in the valuation scenario at the maturities dates. The instrument was valued by calculating the cash flow that would be obtained or paid by theoretically closing out the position and then discounting that amount. The Company terminated this agreement with Abengoa in October 2017 (see Note 21).

Additionally, the Company signed during the year ended December 31, 2017, currency options with leading international financial institutions, which guarantee a minimum Euro-U.S. dollar exchange rates for the distributions expected from Spanish solar assets made in euros during the years 2017, 2018 and part of 2019.

As stated in Note 3 to these consolidated financial statements, the general policy is to hedge variable interest rates of financing agreements purchasing call options (caps) in exchange of a premium to fix the maximum interest rate cost and contracting floating to fixed interest rate swaps.

As a result, the notional amounts hedged, strikes contracted and maturities, depending on the characteristics of the debt on which the interest rate risk is being hedged, can be diverse:

- Project debt in Euros: the Company hedges between 87% and 100% of the notional amount, maturities until 2030 and average guaranteed interest rates of between 3.20% and 4.87%.

- Project debt in U.S. dollars: the Company hedges between 70% and 100% of the notional amount, including maturities until 2032 and average guaranteed interest rates of between 2.32% and 5.27%.

The table below shows a breakdown of the maturities of notional amounts of derivatives designated as cash flow hedges as of December 31, 2017 and 2016.

Notionals	**Balance as of December 31, 2017**		**Balance as of December 31, 2016**	
	Cap	Swap	Cap	Swap
Up to 1 year	42,324	139,939	24,261	75,837
Between 1 and 2 years	45,422	94,285	25,934	199,832
Between 2 and 3 years	48,215	103,536	27,880	83,897
Subsequent years	620,378	1,893,850	400,239	1,500,789
Total	**$ 756,339**	**$ 2,231,611**	**$ 478,314**	**$ 1,860,355**

The table below shows a breakdown of the maturity of the fair values of derivatives designated as cash flow hedges as of December 31, 2017 and 2016. The net position of the fair value of caps and swaps for each year end reconciles with the net position of derivative assets and derivative liabilities in the consolidated statement of financial position:

Fair value	Balance as of December 31, 2017		Balance as of December 31, 2016	
	Cap	Swap	Cap	Swap
Up to 1 year	347	(13,224)	250	(12,383)
Between 1 and 2 years	978	(14,378)	262	(14,927)
Between 2 and 3 years	396	(15,923)	275	(13,957)
Subsequent years	6,509	(286,206)	3,035	(307,999)
Total	**$ 8,230**	**(329,731)**	**$ 3,822**	**(349,266)**

During 2017, fair value of derivatives increased mainly due to an increase in the fair value of interest rate cash-flow hedges resulting from the increase in future interest rates.

The net amount of the fair value of interest rate derivatives designated as cash flow hedges transferred to the consolidated income statement is a loss of $70,953 thousand (loss of $72,774 thousand in 2016 and a loss of $55,841 thousand in 2015). Additionally, the net amount of the time value component of the cash flow derivatives fair value recognized in the consolidated income statement for the year 2017, 2016 and 2015 has been a loss of $860 thousand, a gain of $1,694 thousand and a gain of $4,234 thousand respectively.

The after-tax result accumulated in equity in connection with derivatives designated as cash flow hedges at the years ended December 31, 2017 and 2016, amount to a $80,968 thousand gain and a $52,797 thousand gain respectively.

Note 10.- Related parties

During the normal course of business, the Company has historically conducted operations with related parties consisting mainly of Abengoa´s subsidiaries and non-controlling interests. The transactions were completed at market rates.

Details of balances with related parties as of December 31, 2017 and 2016 are as follows:

	Balance as of December 31,	
	2017	**2016**
Credit receivables (current)	11,567	12,031
Total current receivables with related parties	**11,567**	**12,031**
Credit receivables (non-current)	2,108	30,505
Total non-current receivables with related parties	**2,108**	**30,505**
Trade payables (current)	63,409	61,338
Total current payables with related parties	**63,409**	**61,338**
Credit payables (non-current)	141,031	101,750
Total non-current payables with related parties	**141,031**	**101,750**

Receivables from related parties as of December 31, 2017 include the remaining portion of Abengoa Debt and Equity Instruments received further to the implementation of Abengoa´s restructuring agreement, pending to be sold. These instruments are accounted for at fair value for $1,715 thousand as of December 31, 2017 and classified as current (see Note 8).

As of December 31, 2016, receivables with related parties primarily corresponded to the preferred equity investment in ACBH for a total amount of $30,488 thousand, classified as non-current (see Note 8).

Trade payables (current) primarily relate to payables for Operation and Maintenance services. Credit payables (non-current) primarily relate to payables of projects companies with partners accounted for as non-controlling interests in these consolidated financial statements.

The transactions carried out by entities included in these consolidated financial statements with related parties not included in the consolidation perimeter of Atlantica Yield, primarily with Abengoa and with subsidiaries of Abengoa, during the twelve-month periods ended December 31, 2017, 2016 and 2015 have been as follows:

	For the year ended December 31,		
	2017	2016	2015
Sales	-	-	44,260
Services rendered	3,495	1,220	523
Services received	(114,416)	(115,779)	(106,737)
Financial income	74	60	1,466
Financial expenses	(1,154)	(2,460)	(1,968)

Services received primarily include operation and maintenance services received by some assets. Until December 2015, sales related to sale of energy by Spanish Solar plants were sometimes made through an Abengoa company acting as an agent for the plant. This service is not provided anymore by Abengoa since then.

The figures detailed in the table above do not include the following financial income recorded in these consolidated financial statements for the year ended December 31, 2017: compensation received from Abengoa in lieu of dividends from ACBH for $10.4 million resulting from the agreement signed with Abengoa in the third quarter of 2016 (see Note 8). As of December 31, 2016, the figures do not include the compensation received from Abengoa in lieu of dividends from ACBH for $28.0 million, income for the cancellation of the subordinated debt Solnova Electricidad S.A. owed to Abener for $7.6 million and income of $1.7 million for discounts received from Abengoa for the prepayment of payables.

In addition, Abengoa maintains a number of obligations under EPC, O&M and other contracts, as well as indemnities covering certain potential risks. Additionally, Abengoa represented that further to the accession to the restructuring agreement, Atlantica Yield would not be a guarantor of any obligation of Abengoa with respect to third parties and agreed to indemnify the Company for any penalty claimed by third parties resulting from any breach in such representations. The Company has contingent assets, which have not been recognized as of December 31, 2017, related to the obligations of Abengoa referred above, which result and amounts will depend on the occurrence of uncertain future events.

As explained in Note 1, in November 2017 the Company signed a consent in relation to the Solana and Mojave projects which reduces the minimum ownership required by Abengoa in Atlantica Yield to 16%, subject to certain conditions precedent most of which are beyond the control of the Company, including several payments by Abengoa to Solana before December 2017 and February 2018 (subsequently this date was postponed to May 2018). These payments for a total of $120 million are related to Abengoa’s obligations as EPC contractor in Solana and would be used to repay Solana project debt ($80 million), for current and potential required additional repairs in the plant ($25 million) and for covering other Abengoa obligations ($15 million). Additionally, Abengoa has recognized other obligations with Solana for $6.5 million per semester over 10 years starting in December 2018. In December 2017 Solana received $42.5 million related to Abengoa´s obligation as EPC contractor. The aforementioned amounts are based on the EPC Contract guarantee for liquidated damages considering the average production during the first three years of ramp-up period of the plant which is a service-concession arrangement under IFRIC 12 (intangible asset). For the $42.5 million collected before the end of December 2017, the Company reduced the value of the intangible asset since this amount was a variable consideration. The rest of the amounts to be paid by Abengoa after December 31, 2017 will be accounted for in the same manner, as a reduction of the value of the asset when the different installments are collected. In addition, the amortization of the plant will also be adjusted accordingly.

The Company entered into a Financial Support Agreement on June 13, 2014 under which Abengoa agreed to maintain any guarantees and letters of credit that have been provided by it on behalf of or for the benefit of Atlantica Yield and its affiliates for a period of five years. As of December 2017 the aforementioned guarantees amounted to $31.5 million In the context of that agreement in which Atlantica Yield agreed that it shall use commercially reasonable efforts to replace guarantees, on June 2017, it agreed to replace guarantees amounting to $112 million previously issued by Abengoa. During the third quarter of 2017, the Company issued the aforementioned guarantees and received from Abengoa a payment of €7.8 million for existing debts.

At the date of the initial offering, the Company entered into a series of agreements to receive management, general and administrative services from Abengoa (the “Support Services Agreement” and “Executive Service Agreement”), and corresponding fees were properly accounted for as other operating expenses. The Executive Service Agreement was canceled in February 2015. During the year 2015 and 2016, some employees of Abengoa delivering services under the Support Services Agreement were transferred to entities within the consolidation perimeter of Atlantica Yield and the Support Services Agreement was cancelled. In addition, some external employees were hired. This resulted in the Company increasing its employee benefit expenses as shown in the consolidated income statement for the years 2015, 2016 and 2017.

Note 11.- Clients and other receivable

Clients and other receivable as of December 31, 2017 and 2016, consist of the following:

	Balance as of December 31,	
	2017	**2016**
Trade receivables	186,728	151,199
Tax receivables	39,607	29,705
Prepayments	6,375	10,261
Other accounts receivable	11,739	16,456
Total	**244,449**	**207,621**

As of December 31, 2017 and 2016, the fair value of clients and other accounts receivable does not differ significantly from its carrying value.

Trade receivables in foreign currency as of December 31, 2017 and 2016, are as follows:

	Balance as of December 31,	
	2017	**2016**
Euro	109,165	98,798
Rand	23,792	12,807
Other	7,363	7,151
Total	**140,320**	**118,756**

The following table shows the maturity of Trade receivables as of December 31, 2017 and 2016:

	Balance as of December 31,	
	2017	**2016**
Up to 3 months	186,728	151,199
Total	**186,728**	**151,199**

Note 12.- Cash and cash equivalents

The following table shows the detail of Cash and cash equivalents as of December 31, 2017 and 2016:

	Balance as of December 31,	
	2017	**2016**
Cash at bank and on hand	669,387	594,811
Total	**669,387**	**594,811**

Cash includes funds held to satisfy the customary requirements of certain non-recourse debt agreements within the Company´s projects amounting to $263 million.

The following breakdown shows the main currencies in which cash and cash equivalent balances are denominated:

	Balance as of December 31,	
Currency	**2017**	**2016**
U.S. dollar	319,400	343,954
Euro	288,625	196,382
Algerian Dinar	13,628	10,736
South African Rand	40,999	39,689
Others	6,735	4,050
Total	**669,387**	**594,811**

Note 13.- Equity

On June 18, 2014, Atlantica Yield closed its initial public offering issuing 24,850,000 ordinary shares. The shares were sold at a price of $29 per share and as a result the Company raised $720,650 thousand of gross proceeds. The Company recorded $2,485 thousand as Share Capital and $682,810 thousand as Additional Paid in Capital, included in Atlantica Yield reserves as of December 31, 2016, corresponding to the total net proceeds of the offering. The underwriters further purchased 3,727,500 additional shares from the selling shareholder, a subsidiary wholly owned by Abengoa, at the public offering price less fees and commissions to cover over-allotments (“greenshoe”) driving the total proceeds of the offering to $828,748 thousand.

Atlantica Yield’s shares began trading on the NASDAQ Global Select Market under the symbol “ABY” on June 13, 2014. The symbol changed to “AY” on November 11, 2017.

On January 22, 2015, Abengoa closed an underwritten public offering and sale in the United States of 10,580,000 of ordinary shares of the Company for total proceeds of $327,980,000 (or $31 per share). As a result of such offering, Abengoa reduced its stake in the Company from 64.3% to 51.1% of its shares.

On May 14, 2015 Atlantica Yield issued 20,217,260 new shares at $33.14 per share, which was based on a 3% discount versus the May 7, 2015 closing price. Abengoa subscribed for 51% of the newly-issued shares and maintained its previous stake in Atlantica Yield. The proceeds were primarily used by Atlantica Yield to finance asset acquisitions in May and June 2015.

On July 14, 2015, Abengoa sold 2,000,000 shares of Atlantica Yield under Rule 144, reducing its stake to 49.1%.

As of the date hereof, according to Abengoa´s beneficial ownership reporting, Abengoa has delivered an aggregate of 7,595,639 Ordinary Shares to holders that exercised their option to exchange the $279,000 thousand principal amount of exchangeable notes due 2017 issued by Abengoa on March 5, 2015 (the “Exchangeable Notes”) for shares of Atlantica Yield. The Exchangeable Notes are exchangeable, at the option of their holders, for ordinary shares of Atlantica Yield. These operations reduced Abengoa´s stake to 41.47% as of December 31, 2017.

As of December 31, 2017, the share capital of the Company amounts to $10,021,726 represented by 100,217,260 ordinary shares completely subscribed and disbursed with a nominal value of $0.10 each, all in the same class and series. Each share grants one voting right.

Atlantica Yield reserves as of December 31, 2017 are made up of share premium account and distributable reserves.

Retained earnings include results attributable to Atlantica Yield, the impact of the Asset Transfer in equity and the impact of the assets acquisition under the ROFO agreement in equity. The Asset Transfer and the acquisitions under the ROFO agreement were recorded in accordance with the Predecessor accounting principle, given that all these transactions occurred before December 2015, when Abengoa still had control over Atlantica Yield.

Non-controlling interests fully relate to interests held by JGC in Solacor 1 and Solacor 2, by Idae in Seville PV, by Itochu Corporation in Solaben 2 and Solaben 3, by Algerian Energy Company, SPA and Valoriza Agua S.L. in Skikda and by Industrial Development Corporation of South Africa (IDC) and Kaxu Community Trust in Kaxu Solar One (Pty) Ltd.

Additional information of subsidiaries including material Non-controlling interests as of December 31, 2017 and 2016, are disclosed in Appendix IV.

Dividends declared during the year 2017:

- On February 27, 2017, the Board of Directors declared a dividend of $0.25 per share corresponding to the four quarter of 2016. The dividend was paid on March 15, 2017. From that amount, the Company retained $10.4 million of the dividend attributable to Abengoa;

- On May 15, 2017, the Board of Directors declared a dividend of $0.25 per share corresponding to the first quarter of 2017. The dividend was paid on June 15, 2017;

- On August 3, 2017, the Board of Directors declared a dividend of $0.26 per share corresponding to the second quarter of 2017. The dividend was paid on September 15, 2017;

- On November 13, 2017, the Board of Directors declared a dividend of $0.29 per share corresponding to the third quarter of 2017. The dividend was paid on December 15, 2017.

In addition, as of December 31, 2017, there was no treasury stock and there have been no transactions with treasury stock during the period then ended.

Note 14.- Corporate debt

The breakdown of the corporate debt as of December 31, 2017 and 2016 is as follows:

	Balance as of December 31,	
Non-current	**2017**	**2016**
Credit Facilities with financial entities	320,783	123,804
Notes and Bonds	253,393	252,536
Total Non-Current	**574,176**	**376,340**

Current	Balance as of December 31, 2017	2016
Credit Facilities with financial entities	65,833	289,035
Notes and Bonds	3,074	2,826
Total Current	**68,907**	**291,861**

On November 17, 2014, the Company issued the Senior Notes due 2019 in an aggregate principal amount of $255,000 thousand (the “2019 Notes”). The 2019 Notes accrue annual interest of 7.00% payable semi-annually beginning on May 15, 2015 until their maturity date of November 15, 2019.

On December 3, 2014, the Company entered into a credit facility of up to $125,000 thousand with Banco Santander, S.A., Bank of America, N.A., Citigroup Global Markets Limited, HSBC Bank plc and RBC Capital Markets, as joint lead arrangers and joint bookrunners (the “Credit Facility Tranche A”). On December 22, 2014, the Company drew down $125,000 thousand under the Credit Facility Tranche A. Loans accrue interest at a rate per annum equal to: (A) for Eurodollar rate loans, LIBOR plus 2.75% and (B) for base rate loans, the highest of (i) the rate per annum equal to the weighted average of the rates on overnight U.S. Federal funds transactions with members of the U.S. Federal Reserve System arranged by U.S. Federal funds brokers on such day plus 1/2 of 1.00%, (ii) the U.S. prime rate and (iii) LIBOR plus 1.00%, in any case, plus 1.75%. The interest rate on the Credit Facility Tranche A is fully hedged by an interest rate swap contracted with HSBC Bank with maturity date December 24, 2018, resulting in the Company paying a net fixed interest rate of 4.7%. Loans under the Credit Facility Tranche A will mature in December 2018. Loans prepaid by the Company may be reborrowed. The Credit Facility Tranche A is secured by pledges of the shares of the guarantors which the Company owns.
$8,000 thousand of the loans under the Credit Facility Tranche A were partially repaid on September 25, 2017 and for $63,000 thousand on December 27, 2017. As of December 31, 2017, the remaining $54,000 of nominal of the Tranche A has been classified as Current (Non-Current as of December 31,2016), as its maturity is in December 2018.

On June 26, 2015, the Company increased its existing $125 million Credit Facility with a revolver tranche B for an amount of $290,000 thousand (the “Credit Facility Tranche B”). On September 9, 2015, Credit Facility Tranche B was fully drawn down and the proceeds were used for the acquisition of Solaben 1/6. Loans under the Tranche B Credit Facility accrue interest at a rate per annum equal to: (A) for Eurodollar rate loans, LIBOR plus 2.50% and (B) for base rate loans, the highest of (i) the rate per annum equal to the weighted average of the rates on overnight U.S. Federal funds transactions with members of the U.S. Federal Reserve System arranged by U.S. Federal funds brokers on such day plus 1/2 of 1.00%, (ii) the U.S. prime rate and (iii) LIBOR plus 1.00%, in any case, plus 1.50%. Tranche B of the Credit Facility was signed for a total amount of $290,000 thousand with Bank of America, N.A., as global coordinator and documentation agent and Barclays Bank plc and UBS AG, London Branch as joint lead arrangers and joint bookrunners. The Credit Facility Tranche B was classified as Current for $288,317 thousand as of December 31, 2016 (Non-Current as of December 31,2015) as it matured in December 2017. Loans under the Credit facility Tranche B were fully repaid and canceled on February 28, 2017.

On February 10, 2017, the Company issued Senior Notes due 2022, 2023, 2024 (the “Note Issuance Facility”), in an aggregate principal amount of €275,000 thousand. The 2022 to 2024 Notes accrue annual interest, equal to the sum of (i) EURIBOR plus (ii) 4.90%, as determined by the Agent. Interest on the Notes will be payable in cash quarterly in arrears on each interest payment date. The Company will make each interest payment to the holders of record on each interest payment date. The interest rate on the Note Issuance Facility is fully hedged by two interest rate swaps contracted with Jefferies Financial Services, Inc. with effective date March 31, 2017 and maturity date December 31, 2022, resulting in the Company paying a net fixed interest rate of 5.5% on the Note Issuance Facility. Changes in fair value of these interest rate swaps have been recorded in the consolidated income statement. The Note Issuance Facility is a € denominated liability for which the Company applies net investment hedge accounting. When converted to US$ at US$/€ closing exchange rate, it contributes to reduce the impact in translation difference reserves generated in the equity of these consolidated financial statements by the conversion of the net assets of the Spanish solar assets into US$.

On July 20, 2017, the Company signed a credit facility (the "Credit Facility 2017") for up to €10 million, approximately $11.9 million, which is available in euros or US dollars. Amounts drawn accrue interest at a rate per year equal to EURIBOR plus 2.25% or LIBOR plus 2.25%, depending on the currency. The credit facility has a maturity date of July 20, 2018. As of December 31, 2017, the Company drew down the credit facility in full and used the entire proceeds to prepay a part of the Tranche A of the Credit Facility.

Current corporate debt corresponds to the accrued interest on the Notes, to the outstanding amount of the Tranche A and to the amount of the Credit Facility obtained in July 2017.

The repayment schedule for the Corporate debt, at the end of 2017 is as follows:

	2018	2019	2020	2021	2022	Subsequent years	Total
Credit Facility Tranche A	53,778	-	-	-	-	-	53,778
Note Issuance Facility	107	-	-	-	107,316	213,467	320,890
Credit Facility 2017	11,948	-	-	-	-	-	11,948
2019 Notes	3,074	253,393	-	-	-	-	256,467
Total	**68,907**	**253,393**	**-**	**-**	**107,316**	**213,467**	**643,083**

The following table details the movement in Corporate debt for the year 2017, split between cash and non-cash items:

	January 1, 2017	Cash Flow	Non-cash changes	December 31, 2017
Corporate debt	668,201	(68,372)	43,254	643,083

The non-cash changes primarily relates to currency translation differences.

Note 15.- Project debt

The main purpose of the Company is the long-term ownership and management of contracted concessional assets, such as renewable energy, efficient natural gas, electric transmission line assets and water, which are financed through project debt. This Note shows the project debt linked to the contracted concessional assets included in Note 6 of these consolidated financial statements.

Project debt is generally used to finance contracted assets, exclusively using as guarantee the assets and cash flows of the company or group of companies carrying out the activities financed. In most of the cases, the assets and/or contracts are set up as guarantee to ensure the repayment of the related financing.

Compared with corporate debt, project debt has certain key advantages, including greater leverage period permitted and a longer tenor.

The variations for 2017 and 2016 of project debt have been the following:

	Project debt - long term	Project debt - short term	Total
Balance as of December 31, 2016	4,629,184	701,283	5,330,467
Increases	52,027	304,707	356,734
Decreases	(42,560)	(509,131)	(551,691)
Currency translation differences	316,646	23,052	339,698
Reclassifications	273,620	(273,620)	-
Balance as of December 31, 2017	**5,228,917**	**246,291**	**5,475,208**

The line "Increases" includes primarily accrued interests for the year.

Main variations in Project debt during the year 2017 are the result of:

- Net decrease primarily due to repayment of debt, considering that interests accrued are offset by a similar amount of interests paid during the year. Decrease in long-term debt primarily relates to the partial repayment of Solana debt using the indemnity received from Abengoa in December 2017 for $42.5 million (see Note 10);

- A reclassification of the entire debt of Kaxu and Cadonal projects from short term to long term during the year 2017 as a result of the waiver obtained for Kaxu in March 2017 and the completion of certain pending conditions for Cadonal in October 2017. In addition, in 2017, Kaxu's debt coverage ratio did not reach the minimum threshold due to the technical problems that the plant experienced since the end of 2016. However, the lenders of the project finance agreement granted a waiver to the asset and therefore reclassification of the debt to short-term does not apply in this case.

	Project debt - long term	**Project debt - short term**	**Total**
Balance as of December 31, 2015	3,574,464	1,896,205	5,470,669
Increases	36,842	329,434	366,276
Decreases	-	(480,969)	(480,969)
Currency translation differences	(64,426)	38,917	(25,509)
Reclassifications	1,082,304	(1,082,304)	-
Balance as of December 31, 2016	**4,629,184**	**701,283**	**5,330,467**

The line "Increases" includes primarily accrued interests for the year.

Main variations in Project debt during the year 2016 were the result of:

- Net decrease primarily due to repayment of debt; considering that interests accrued were offset by a similar amount of interests paid during the year;

- A reclassification of the entire debt of Solana and Mojave projects from short term to long term as of December 31, 2016 considering that as a result of the forbearance signed in December 2016, Abengoa cross-defaults will no longer trigger acceleration remedies in the Solana or Mojave financing agreements.

Debts of Kaxu and Cadonal projects remained classified as short term in accordance with International Accounting Standards 1 ("IAS 1"), "Presentation of Financial Statements" as of December 31, 2016. The waiver of the cross-default provisions related to Abengoa that had been obtained for Cadonal during 2016 was subject to the completion of certain conditions.

The repayment schedule for Project debt in accordance with the financing arrangements, at the end of 2017 is as follows and is consistent with the projected cash flows of the related projects.

2018		**2019**	**2020**	**2021**	**2022**	**Subsequent years**	**Total**
Interest Repayment	**Nominal repayment**						
21,612	224,679	246,471	265,002	280,303	313,559	4,123,582	5,475,208

In 2016, the Company refinanced ATN2 debt. In 2017, the Company did not enter into any new project debt.

Current and non-current loans with credit entities include amounts in foreign currencies for a total of $2,778,043 thousand as of December 31, 2017 ($2,564,291 thousand as of December 31, 2016).

The following table details the movement in Project debt for the year 2017, split between cash and non-cash items:

	January 1, 2017	Cash Flow	Non-cash changes	December 31, 2017
Project debt	5,330,467	(248,472)	393,212	5,475,208

The non-cash changes primarily relates to currency translation differences.

The equivalent in U.S. dollars of the most significant foreign-currency-denominated debts held by the Company is as follows:

	Balance as of December 31,	
Currency	**2017**	**2016**
Euro	2,286,771	2,102,985
Algerian Dinar	35,093	41,598
Rand	456,179	419,708
Total	**2,778,043**	**2,564,291**

All of the Company’s financing agreements have a carrying amount close to its fair value.

Note 16.- Grants and other liabilities

	Balance as of December 31,	
	2017	**2016**
Grants	1,225,877	1,297,755
Other liabilities	410,183	314,290
Grant and other non-current liabilities	**1,636,060**	**1,612,045**

As of December 31, 2017, the amount recorded in Grants corresponds primarily to the ITC Grant awarded by the U.S. Department of the Treasury to Solana and Mojave for a total amount of $771 million ($803 million as of December 31, 2016), which was primarily used to fully repay the Solana and Mojave short-term tranche of the loan with the Federal Financing Bank. The amount recorded in Grants as a liability is progressively recorded as other income over the useful life of the asset.

The remaining balance of the “Grants” account corresponds to loans with interest rates below market rates for Solana and Mojave for a total amount of $452 million ($492 million as of December 31, 2016). Loans with the Federal Financing Bank guaranteed by the Department of Energy for these projects bear interest at a rate below market rates for these types of projects and terms. The difference between proceeds received from these loans and its fair value, is initially recorded as “Grants” in the consolidated statement of financial position, and subsequently recorded in “Other operating income” starting at the entry into operation of the plants. Total amount of income for these two types of grants for Solana and Mojave is $59.8 million and $57.0 million for the year ended December 31, 2017 and 2016, respectively.

Other liabilities mainly relate to the investment from Liberty Interactive Corporation (‘Liberty’) made on October 2, 2013 for an amount of $300 million. The investment was made in class A shares of Arizona Solar Holding, the holding of Solana Solar plant in the United States. Such investment was made in a tax equity partnership which permits the partners to have certain tax benefits such as accelerated depreciation and ITC.

According to the stipulations of IAS 32 and in spite of the fact that the investment of Liberty is in shares, it does not qualify as equity and has been classified as a liability as of December 31, 2017 and 2016. The liability is recorded in Grants and other liabilities for a total amount of $352 million ($263 million as of December 31, 2016) and its current portion is recorded in other current liabilities for the remaining amount (see Note 17). This liability has been initially valued at fair value, calculated as the present value of expected cash-flows during the useful life of the concession, and is then measured at amortized cost in accordance with the effective interest method, considering the most updated expected future cash-flows.

Note 17.- Trade payables and other current liabilities

Trade payable and other current liabilities as of December 31, 2017 and 2016 are as follows:

	Balance as of December 31,	
Item	**2017**	**2016**
Trade accounts payables	107,662	121,527
Down payments from clients	6,466	6,153
Suppliers of concessional assets current	236	380
Liberty (see Note 16)	-	21,461
Other accounts payable	40,780	10,984
Total	**155,144**	**160,505**

Trade accounts payables mainly relate to the operating and maintenance of the plants.

Nominal values of Trade payable and other current liabilities are considered to approximately equal to fair values and the effect of discounting them is not significant.

Other account payable primarily include subordinated debt of Mojave with Abener Teyma Mojave General Partnership (Abener), a related party, with maturity date on October 2018. The repayment will occur if certain technical conditions are fulfilled.

Note 18.- Income Tax

All the companies included in the Company file income taxes according to the tax regulations in force in each country on an individual basis or under consolidation tax regulations.

The consolidated income tax has been calculated as an aggregation of income tax expenses/income of each individual company. In order to calculate the taxable income of the consolidated entities individually, the accounting result is adjusted for temporary and permanent differences, recording the corresponding deferred tax assets and liabilities. At each consolidated income statement date, a current tax asset or liability is recorded, representing income taxes currently refundable or payable. Deferred income taxes reflect the net tax effects of temporary differences between the carrying amount of assets and liabilities for financial statement and income tax purposes, as determined under enacted tax laws and rates.

Income tax payable is the result of applying the applicable tax rate in force to each tax-paying entity, in accordance with the tax laws in force in the country in which the entity is registered. Additionally, tax deductions and credits are available to certain entities, primarily relating to inter-company trades and tax treaties between various countries to prevent double taxation.

As of December 31, 2017, and 2016, the analysis of deferred tax assets and deferred tax liabilities is as follows:

Deferred tax assets	Balance as of December 31,	
Concept	**2017**	**2016**
Net tax credits for operating losses carryforwards	71,219	102,804
Temporary differences derivatives financial instruments	93,719	99,930
Other temporary differences	198	157
Total deferred tax assets	**165,136**	**202,891**

Most of the net tax credits for operating losses carryforwards corresponds to Peru, Kaxu and solar plants in Spain as of December 31, 2017.

The balance as of December 31, 2016 also included significant net deferred tax assets for Solana and Mojave, which are now net deferred tax liabilities as of December 31, 2017, due to the following:

- In December 2017 a tax reform, the Tax Cuts and Jobs Act, was enacted in the U.S., consisting mainly in a decrease in the corporate tax rate from 35% to 21% effective 1st of January 2018. The Company therefore adjusted the deferred tax assets and liabilities of its U.S. entities using the new enacted corporate tax rate as of December 31, 2017, resulting in a loss of $19 million recorded in the consolidated income statement for the year ended December 31, 2017;

- In addition, the U.S. Internal Revenue Code ("IRC") Section 382 establishes an annual limitation on the use of U.S. Net Operating Losses ("NOLs") as a result of an ownership change. An "ownership change" would occur if the direct and indirect "5-percent shareholders", as defined under Section 382 of the IRC, collectively increased their ownership in the Company by more than 50 percentage points over a rolling three-year period. The Company experienced during 2017 an ownership change due to Abengoa´s restructuring and changes in its shareholders´s base. As a result, the U.S. NOLs carryforwards generated through the date of change are subject to an annual limitation under Section 382, which resulted in a derecognition of deferred tax assets previously recognized amounting to $96 million corresponding to an amount of $387 million of NOLs and also taking into consideration the newly enacted corporate tax rate of 21%. This loss has been recorded in the consolidated income statement for the year ended December 31, 2017.

Temporary differences for derivatives financial instruments are mainly due to ACT ($18 million) and solar plants in Spain ($69 million).

In relation to tax loss carryforwards and deductions pending to be used recorded as deferred tax assets, the entities evaluate its recoverability projecting forecasted taxable income for the upcoming years and taking into account their tax planning strategy. Deferred tax liabilities reversals are also considered in these projections, as well as any limitation established by tax regulations in force in each tax jurisdiction.

Deferred tax liabilities	**Balance as of December 31,**	
Concept	**2017**	**2016**
Temporary differences tax/book amortization	113,432	28,810
Other temporary differences tax/book value of contracted concessional assets	66,247	61,818
Other temporary differences	6,904	4,409
Total deferred tax liabilities	**186,583**	**95,037**

As of December 31, 2017, temporary differences as a result of accelerated tax amortization resulted in a net deferred tax liability position. These are primarily due to Solana and Mojave ($63 million) and solar plants in Spain ($51 million). The increase is primarily due to an impact on the U.S. entities as a result of the tax reform and U.S. Internal Revenue Code Section 382 as previously described.

Other temporary differences tax/book value of contracted concessional assets, which resulted in a net deferred tax liability position relates primarily to ACT in both periods.

The movements in deferred tax assets and liabilities during the years ended December 31, 2017 and 2016 were as follows:

Deferred tax assets	**Amount**
As of January 1, 2016	191,314
Increase/decrease through the consolidated income statement	16,033
Increase/decrease through other consolidated comprehensive income (equity)	(5,701)
Other movements	1,245
As of December 31, 2016	**202,891**
Increase/decrease through the consolidated income statement	(31,421)
Increase/decrease through other consolidated comprehensive income (equity)	(13,312)
Other movements	6,978
As of December 31, 2017	**165,136**

Deferred tax liabilities	**Amount**
As of January 1, 2016	79,654
Increase/decrease through the consolidated income statement	16,681
Increase/decrease through other consolidated comprehensive income (equity)	(62)
Other movements	(1,236)
As of December 31, 2016	**95,037**
Increase/decrease through the consolidated income statement	86,418
Increase/decrease through other consolidated comprehensive income (equity)	-
Other movements	5,128
As of December 31, 2017	**186,583**

Details for income tax for the years ended December 31, 2017, 2016 and 2015 are as follows:

	For the twelve-month period ended December 31,		
Item	**2017**	**2016**	**2015**
Current tax	**(1,998)**	**(1,018)**	**(2,182)**
Deferred tax	**(117,839)**	**(648)**	**(21,608)**
- relating to the origination and reversal of temporary differences	(98,508)	(648)	(22,492)
- relating to changes in tax rates	(19,331)	-	884
Total income tax benefit/(expense)	**(119,837)**	**(1,666)**	**(23,790)**

The reconciliation between the theoretical income tax resulting from applying an average statutory tax rate to income/(loss) before income tax and the actual income tax expense recognized in the consolidated income statements for the years ended December 31, 2017, 2016 and 2015, are as follows:

	For the year ended December 31,		
Concept	**2017**	**2016**	**2015**
Consolidated income / (loss) before taxes	14,950	3,333	(174,396)
Average statutory tax rate	30%	30%	30%
Corporate income tax at average statutory tax rate	**(4,485)**	**(1,000)**	**52,319**
Income tax of associates, net	1,765	2,110	2,341
Differences in foreign tax rates	3,304	(4,930)	(2,389)
Permanent differences	19,324	11,121	(19,456)
Incentives, deductions, and unrecognized tax losses carryforwards	(20,994)	(11,110)	(58,039)
Change in corporate income tax	(19,331)	-	884
U.S. Internal Revenue Code Section 382	(96,328)	-	-
Other non-taxable income/(expense)	(3,092)	2,143	550
Corporate income tax	**(119,837)**	**(1,666)**	**(23,790)**

Permanent differences in 2017, 2016 and 2015 are mainly due to ACT (Mexico).

The main implications derived from the Tax Cuts and Jobs Act in the U.S. entities are:

- A reduction of the Federal income tax rate from 35% to 21%, effective since January 1, 2018. This measure will imply a reduction of the tax burden of the Company. The effect on the deferred tax assets and liabilities has resulted in a $19 million loss;

- A limitation of the deduction for net interest expense of all businesses in the U.S. The new limitation is imposed on net interest expense that exceeds 30% of EBITDA from 2018 to 2021, and 30% of EBIT from 2022 onwards. Interests disallowed would be deducted in the future in the event that those limits are not exceeded. After having considered the impacts of Section 382 commented above, the Company does not expect significant negative effects from this net interest expense limitation;

- NOLs arising in tax years beginning after 2017 would be limited to 80% of taxable income. For new NOLs recognized after 2017, an indefinite carryforward would be allowed. The limitation of 80% is not applicable for NOLs generated before 2018. For existing NOLs before 2018, a carryforward of 20 years is still applicable. The new limitation does not trigger adverse tax effects to the U.S. subsidiaries of the Company considering the amount of NOLs to be generated in upcoming years and the projected amount of taxable income of these entities after having considered the impacts of Section 382;

- Base erosion anti-abuse tax (BEAT): The BEAT applies to certain U.S. corporations that make relevant deductible payments to foreign affiliates. The excess of 10% of a corporation's taxable income increased by those payments to foreign related parties over its regular tax liability, will be the base erosion tax due. BEAT provisions do not trigger adverse tax consequences for the U.S. subsidiaries of the Company considering the amount of payments made to foreign affiliates for management and support services;

- Potential tax erosion in the U.S.: The Company does not expect to have material adverse tax consequences in the U.S. subsidiaries as a result of the measures previously described.

Note 19.- Third-party guarantees and commitments

Third-party guarantees

At the close of 2017 the overall sum of Bank Bond and Surety Insurance directly deposited by the subsidiaries of the Company as a guarantee to third parties (clients, financial entities and other third parties) amounted to $32,428 thousand attributed to operations of technical nature ($27,163 thousand as of December 31, 2016). In addition, in the third quarter of 2017 the Company issued the guarantees amounting to $112 million previously issued by Abengoa related to operations of technical nature (see Note 10).

Contractual obligations

The following table shows the breakdown of the third-party commitments and contractual obligations as of December 31, 2017 and 2016:

2017	Total	2018	2019 and 2020	2021 and 2022	Subsequent
Corporate debt	643,083	68,907	253,393	107,316	213,467
Loans with credit institutions (project debt)	4,628,289	215,117	457,853	539,466	3,415,853
Notes and bonds (project debt)	846,919	31,174	53,620	54,395	707,730
Purchase commitments	3,149,813	141,867	230,014	259,845	2,518,087
Accrued interest estimate during the useful life of loans	3,129,321	340,481	630,108	559,856	1,598,876

2016	Total	2017	2018 and 2019	2020 and 2021	Subsequent
Corporate debt	668,201	291,861	376,340	-	-
Loans with credit institutions (project debt)*	4,498,930	183,929	388,679	459,361	3,466,961
Notes and bonds (project debt)	831,538	27,225	49,422	48,740	706,151
Purchase commitments	2,894,146	136,032	263,398	246,904	2,247,812
Accrued interest estimate during the useful life of loans	3,356,750	332,408	617,852	543,927	1,862,563

* According to contracted maturities.

Legal Proceedings

On October 17, 2016, ACT received a request for arbitration from the International Court of Arbitration of the International Chamber of Commerce presented by Pemex. Pemex is requesting compensation for damages caused by a fire that occurred in their facilities during the construction of the ACT cogeneration plant in December 2012, for a total amount of approximately $20 million. On July 5, 2017, Seguros Inbursa, the insurer of Pemex, joined as a second claimant in the process. The Company does not expect this proceeding to have a material adverse effect on their financial position, cash flows or results of operations. In the event that the arbitration results in a negative outcome, the Company expects these damages to be covered by the existing insurance policy.

A number of Abengoa's subcontractors and insurance companies that issued bonds covering such contracts in the United States have included subsidiaries of the Company as co-defendants in claims against Abengoa. Generally the subsidiaries of the Company have been dismissed as defendants at early stages of the processes but there remain pending cases including Arb Inc. with a potential total claim of approximately $33 million and a group of insurance companies with a potential total claim of approximately $200 million. Based on the assessment of the Company with information currently available, the Company does not expect these proceedings, individually or in the aggregate, to have a material adverse effect on its financial position, cash flows or results of operations.

The Company is not a party to any other significant legal proceeding other than legal proceedings arising in the ordinary course of its business. The Company is party to various administrative and regulatory proceedings that have arisen in the ordinary course of business. While the Company does not expect these proceedings, either individually or in the aggregate, to have a material adverse effect on its financial position or results of operations, because of the nature of these proceedings the Company is not able to predict their ultimate outcomes, some of which may be unfavorable to the Company.

Note 20.- Other operating income and expenses

The table below shows the detail of Other operating income and expenses for the years ended December 31, 2017, 2016 and 2015:

	For the twelve-month year ended December 31,		
Other operating income	**2017**	**2016**	**2015**
Grants	59,707	59,085	67,859
Income from various services and insurance proceeds	21,137	6,453	998
Total	**80,844**	**65,538**	**68,857**

	For the twelve-month year ended December 31,		
Other operating expenses	**2017**	**2016**	**2015**
Leases and fees	(6,641)	(5,309)	(3,865)
Operation and maintenance	(129,873)	(133,292)	(116,405)
Independent professional services	(36,178)	(30,515)	(19,046)
Supplies	(20,350)	(17,177)	(18,001)
Insurance	(24,289)	(23,390)	(20,277)
Levies and duties	(52,409)	(44,440)	(32,352)
Other expenses	(14,721)	(6,195)	(14,882)
Total	**(284,461)**	**(260,318)**	**(224,828)**

Grants income mainly relate to ITC cash grants and implicit grants recorded for accounting purposes in relation to the FFB loans with interest rates below market rates in Solana and Mojave projects (See Note 16).

Residual increase in other operating income relates primarily to insurance proceeds from claims in some assets of the Company.

The Company changed the presentation of "Other operating expenses" in 2016 to better reflect the nature of its business and costs. Prior years amounts have been reclassified to conform to the new classification presented in the table above.

Note 21.- Financial Income and expenses

The following table sets forth financial income and expenses for the years ended December 31, 2017, 2016 and 2015:

	For the year ended December 31,		
Financial income	**2017**	**2016**	**2015**
Interest income from loans and credits	325	286	933
Interest rates benefits derivatives: cash flow hedges	682	3,012	2,531
Total	**1,007**	**3,298**	**3,464**

	For the year ended December 31,		
Financial expenses	**2017**	**2016**	**2015**
Expenses due to interest:			
- Loans from credit entities	(253,660)	(242,919)	(197,929)
- Other debts	(137,562)	(90,995)	(81,853)
Interest rates losses derivatives: cash flow hedges	(72,495)	(74,093)	(54,139)
Total	**(463,717)**	**(408,007)**	**(333,921)**

Interests from other debts are primarily interest on the notes issued by ATS, ATN, ATN2, Atlantica Yield and Solaben Luxembourg and interest related to the investment from Liberty. Increase in 2017 is primarily due to the higher increase in the amortized cost of the Liberty debt by $50 million compared to the year 2016 (see Note 16). Losses from interest rate derivatives designated as cash flow hedges correspond primarily to transfers from equity to financial expense when the hedged item is impacting the consolidated income statement.

Other net financial income and expenses

The following table sets out Other net financial income and expenses for the years 2017, 2016 and 2015:

	For the year ended December 31,		
Other financial income / (expenses)	**2017**	**2016**	**2015**
Dividend from ACBH (Brazil)	10,383	27,948	18,400
Impairment preferred equity investment in ACBH (see Note 8)	-	(22,076)	(210,435)
Other financial income	28,809	13,027	1,520
Other financial losses	(20,758)	(10,394)	(9,638)
Total	**18,434**	**8,505**	**(200,153)**

According to the agreement reached with Abengoa in the third quarter of 2016, Abengoa acknowledged that Atlantica Yield is the legal owner of the dividends declared on February 24, 2017 and retained from Abengoa amounting to $10.4 million. As a result, the Company recorded $10.4 million as Other financial income in accordance with the accounting treatment previously given to the ACBH dividend.

Other financial losses for the year ended December 31, 2017 consist primarily of a loss resulting from the derecognition of the fair value assigned to ACBH preferred equity investment and recognition of the Abengoa Debt and Equity Instruments for $5.8 million (see Note 8). Residual items presented as Other financial losses are guarantees and letters of credit, wire transfers, other bank fees and other minor financial expenses.

Other financial income consists primarily of $16.2 million income as a result of the termination of the currency swap agreement with Abengoa (see Note 9) and the profit resulting from the sale of the majority of the Abengoa Debt and Equity instruments for $6.5 million (see Note 8).

Note 22.- Earnings per share

Basic earnings per share for the year 2017 has been calculated by dividing the profit/(loss) attributable to equity holders of the company by the number of shares outstanding. Diluted earnings per share equals basic earnings per share for the period presented.

Item	For the year ended December 31,		
	2017	2016	2015
Profit/(loss) from continuing operations attributable to Atlantica Yield Plc.	(111,804)	(4,855)	(209,005)
Profit/(loss) from discontinuing operations attributable to Atlantica Yield Plc.	-	-	-
Average number of ordinary shares outstanding (thousands) - basic and diluted	**100,217**	**100,217**	**92,795**
Earnings per share from continuing operations (US dollar per share) - basic and diluted	(1.12)	(0.05)	(2.25)
Earnings per share from discontinuing operations (US dollar per share) - basic and diluted	-	-	-
Earnings per share from profit/ (loss) for the period (US dollar per share) - basic and diluted	**(1.12)**	**(0.05)**	**(2.25)**

Note 23.- Other information

23.1 Restricted Net assets

Certain of the consolidated entities are restricted from remitting certain funds to Atlantica Yield plc. as a result of a number of regulatory, contractual or statutory requirements. These restrictions are related to standard requirements to maintain debt service coverage ratios. In addition, some of the assets of the Company have forbearance in relation to cross defaults and change of ownership provisions with Abengoa, under certain conditions. Under the definition of the Securities and Exchange Commission Regulation S-X Rule 12-04, these are also considered restricted for the purposes of this calculation. At December 31, 2017, the accumulated amount of the temporary restrictions for the entire restricted term of these affiliates was $566 million.

The Company performed a test on the restricted net assets of consolidated subsidiaries in accordance with Securities and Exchange Commission Regulation S-X Rule 12-04 and concluded the restricted net assets exceeded 25% of the consolidated net assets of the Company as of December 31, 2017. Therefore, the separate financial statements of Atlantica Yield, Plc. do have to be presented (see Appendix V (Schedule I) for details).

23.2 Subsequent events

On February 27, 2018, the Board of Directors of the Company approved a dividend of $0.31 per share, which is expected to be paid on or about March 27, 2018.

Appendices

Appendix I

Entities included in the Group as subsidiaries as of December 31, 2017

Company name	Project name	Registered address	% of nominal share	Business
ACT Energy México, S. de R.L. de C.V.	ACT	Santa Barbara (Mexico)	100.00	(2)
ABY infraestructuras, S.L.	ABY Infraestructuras	Sevilla (Spain)	100.00	(5)
ABY infrastructures USA LLC.	ABY Infrastructures	Arizona (United States)	100.00	(5)
ABY Concessions Infrastructures, S.LU.	ACIN	Sevilla (Spain)	100.00	(5)
ABY Concessions Perú, S.A.	ACP	Lima (Peru)	100.00	(5)
ABY Holdings USA LLC		Arizona (United States)	100.00	(5)
ASHUSA Inc.	ABSA	Arizona (United States)	100.00	(5)
ABY South Africa (Pty) Ltd	ASA	Pretoria (South Africa)	100.00	(5)
ASUSHI, Inc.	ABSU	Arizona (United States)	100.00	(5)
Atlantica Yield Chile SpA		Santiago de Chile (Chile)	100.00	(5)
ATN, S.A.	ATN	Lima (Peru)	100.00	(1)
ABY Transmisión Sur, S.A.	ATS	Lima (Peru)	100.00	(1)
ACT Holdings, S.A. de C.V.	ACT Holding	México D.F. (Mexico)	100.00	(5)
Aguas de Skikda S.P.A.	Skikda	Dely Ibrahim (Argelia)	51.00	(4)
Arizona Solar One, LLC.	ASO	Colorado (United States)	100,00	(3)
ASO Holdings Company, LLC.	ASOH	Colorado (United States)	100.00*	(5)
ATN 2, S.A.	ATN 2	Lima (Peru)	100.00	(1)
Banitod, S.A..		Montevideo (Uruguay)	100.00	(5)
Cadonal, S.A.	Cadonal	Montevideo (Uruguay)	100.00	(3)
Carpio Solar Inversiones, S.A.	Carpio	Sevilla (Spain)	100.00	(5)
Ecija Solar Inversiones, S.A.	ESI	Sevilla (Spain)	100.00	(5)
Extremadura Equity Investments Sárl.	EEI	Luxembourg (Luxembourg)	100.00	(5)
Fotovoltaica Solar Sevilla, S.A.	Seville PV	Sevilla (Spain)	80.00	(3)
Geida Skikda, S.L.	Geida Skikda	Madrid (Spain)	67.00	(5)
Helioenergy Electricidad Uno, S.A.	Helioenergy 1	Sevilla (Spain)	100.00	(3)
Helioenergy Electricidad Dos, S.A.	Helioenergy 2	Sevilla (Spain)	100.00	(3)
Helios I Hyperion Energy Investments, S.L.	Helios 1	Sevilla (Spain)	100.00	(3)
Helios II Hyperion Energy Investments, S.L.	Helios 2	Sevilla (Spain)	100.00	(3)
Hypesol Energy Holding, S.L.	Hypesol	Sevilla (Spain)	100.00	(5)
Kaxu Solar One (Pty) Ltd.	KSO	Gauteng (South Africa)	51.00	(3)
Logrosán Equity Investments Sárl.	LEI	Luxembourg (Luxembourg)	100.00	(5)
Logrosán Solar Inversiones, S.A.	Logrosan	Sevilla (Spain)	100.00	(5)
Logrosán Solar Inversiones Dos, S.L.	Logrosan 2	Sevilla (Spain)	100.00	(5)
Mojave Solar Holdings, LLC.	MSH	Colorado (United States)	100.00	(5)
Mojave Solar LLC.	Mojave	Arizona (United States)	100.00	(3)
Palmatir S.A.	Palmatir	Montevideo (Uruguay)	100.00	(3)
Palmucho, S.A.	Palmucho	Santiago de Chile (Chile)	100.00	(1)
RRHH Servicios Corporativos, S. de R.L. de C.V.	Servicios Corporativos	Santa Barbara. (Mexico)	100.00	(5)
Sanlucar Solar, S.A.	PS-10	Sevilla (Spain)	100.00	(3)
Solaben Electricidad Uno S.A.	Solaben 1	Caceres (Spain)	100.00	(3)
Solaben Electricidad Dos S.A.	Solaben 2	Caceres (Spain)	70.00	(3)
Solaben Electricidad Tres S.A.	Solaben 3	Caceres (Spain)	70.00	(3)
Solaben Electricidad Seis S.A.	Solaben 6	Caceres (Spain)	100.00	(3)
Solaben Luxembourg S.A.	SL	Luxembourg (Luxembourg)	100.00	(5)
Solacor Electricidad Uno, S.A.	Solacor 1	Sevilla (Spain)	87.00	(3)
Solacor Electricidad Dos, S.A.	Solacor 2	Sevilla (Spain)	87.00	(3)
ABY Servicios Corporativos S.A.	ABYSC	Sevilla (Spain)	100.00	(5)
Solar Processes, S.A.	PS-20	Sevilla (Spain)	100.00	(3)
Solnova Solar Inversiones, S.A.	SSI	Seville (Spain)	100.00	(5)
Solnova Electricidad, S.A.	Solnova 1	Seville (Spain)	100.00	(3)
Solnova Electricidad Tres, S.A.	Solnova 3	Seville (Spain)	100.00	(3)
Solnova Electricidad Cuatro, S.A.	Solnova 4	Seville (Spain)	100.00	(3)
Transmisora Mejillones, S.A.	Quadra 1	Santiago de Chile (Chile)	100.00	(1)
Transmisora Baquedano, S.A.	Quadra 2	Santiago de Chile (Chile)	100.00	(1)

(1) Business sector: Electric transmission lines
(2) Business sector: Efficient natural gas
(3) Business sector: Renewable energy
(4) Business sector: Water
(5) Holding Company
* 100% of Class A shares held by Liberty (US tax equity investor, non-related party).

The Appendices are an integral part of the Notes to the financial statements.

Appendices

Appendix I

Entities included in the Group as subsidiaries as of December 31, 2016

Company name	Project name	Registered address	% of nominal share	Business
ACT Energy México, S. de R.L. de C.V.	ACT	Santa Barbara (Mexico)	100.00	(2)
ABY infraestructuras, S.L.	ABY Infraestructuras	Sevilla (Spain)	100.00	(5)
ABY infrastructures USA LLC.	ABY Infrastructures	Arizona (United States)	100.00	(5)
ABY Concessions Infrastructures, S.LU.	ACIN	Sevilla (Spain)	100.00	(5)
ABY Concessions Perú, S.A.	ACP	Lima (Peru)	100.00	(5)
ASHUSA Inc.	ABSA	Arizona (United States)	100.00	(5)
ABY South Africa (Pty) Ltd	ASA	Pretoria (South Africa)	100.00	(5)
ASUSHI, Inc.	ABSU	Arizona (United States)	100.00	(5)
ATN, S.A.	ATN	Lima (Peru)	100.00	(1)
ABY Transmisión Sur, S.A.	ATS	Lima (Peru)	100.00	(1)
ACT Holdings, S.A. de C.V.	ACT Holding	México D.F. (Mexico)	100.00	(5)
Aguas de Skikda S.P.A.	Skikda	Dely Ibrahim (Argelia)	51.00	(4)
Arizona Solar One, LLC.	ASO	Colorado (United States)	100,00	(3)
ASO Holdings Company, LLC.	ASOH	Colorado (United States)	100.00*	(5)
ATN 2, S.A.	ATN 2	Lima (Peru)	100.00	(1)
Cadonal, S.A.	Cadonal	Montevideo (Uruguay)	100.00	(3)
Carpio Solar Inversiones, S.A.	Carpio	Sevilla (Spain)	100.00	(5)
Ecija Solar Inversiones, S.A.	ESI	Sevilla (Spain)	100.00	(5)
Extremadura Equity Investments Sárl.	EEI	Luxembourg (Luxembourg)	100.00	(5)
Fotovoltaica Solar Sevilla, S.A.	Seville PV	Sevilla (Spain)	80.00	(3)
Geida Skikda, S.L.	Geida Skikda	Madrid (Spain)	67.00	(5)
Helioenergy Electricidad Uno, S.A.	Helioenergy 1	Sevilla (Spain)	100.00	(3)
Helioenergy Electricidad Dos, S.A.	Helioenergy 2	Sevilla (Spain)	100.00	(3)
Helios I Hyperion Energy Investments, S.L.	Helios 1	Sevilla (Spain)	100.00	(3)
Helios II Hyperion Energy Investments, S.L.	Helios 2	Sevilla (Spain)	100.00	(3)
Holding de Energía Eólica S.A.	HE	Montevideo (Uruguay)	100.00	(5)
Hypesol Energy Holding, S.L.	Hypesol	Sevilla (Spain)	100.00	(5)
Kaxu Solar One (Pty) Ltd.	KSO	Gauteng (South Africa)	51.00	(3)
Logrosán Equity Investments Sárl.	LEI	Luxembourg (Luxembourg)	100.00	(5)
Logrosán Solar Inversiones, S.A.	Logrosan	Sevilla (Spain)	100.00	(5)
Logrosán Solar Inversiones Dos, S.L.	Logrosan 2	Sevilla (Spain)	100.00	(5)
Mojave Solar Holdings, LLC.	MSH	Colorado (United States)	100.00	(5)
Mojave Solar LLC.	Mojave	Arizona (United States)	100.00	(3)
Palmatir S.A.	Palmatir	Montevideo (Uruguay)	100.00	(3)
Palmucho, S.A.	Palmucho	Santiago de Chile (Chile)	100.00	(1)
RRHH Servicios Corporativos, S. de R.L. de C.V.	Servicios Corporativos	Santa Barbara. (Mexico)	100.00	(5)
Sanlucar Solar, S.A.	PS-10	Sevilla (Spain)	100.00	(3)
Solaben Electricidad Uno S.A.	Solaben 1	Caceres (Spain)	100.00	(3)
Solaben Electricidad Dos S.A.	Solaben 2	Caceres (Spain)	70.00	(3)
Solaben Electricidad Tres S.A.	Solaben 3	Caceres (Spain)	70.00	(3)
Solaben Electricidad Seis S.A.	Solaben 6	Caceres (Spain)	100.00	(3)
Solaben Luxembourg S.A.	SL	Luxembourg (Luxembourg)	100.00	(5)
Solacor Electricidad Uno, S.A.	Solacor 1	Sevilla (Spain)	87.00	(3)
Solacor Electricidad Dos, S.A.	Solacor 2	Sevilla (Spain)	87.00	(3)
ABY Servicios Corporativos S.A.	ABYSC	Sevilla (Spain)	100.00	(5)
Solar Processes, S.A.	PS-20	Sevilla (Spain)	100.00	(3)
Solnova Solar Inversiones, S.A.	SSI	Seville (Spain)	100.00	(5)
Solnova Electricidad, S.A.	Solnova 1	Seville (Spain)	100.00	(3)
Solnova Electricidad Tres, S.A.	Solnova 3	Seville (Spain)	100.00	(3)
Solnova Electricidad Cuatro, S.A.	Solnova 4	Seville (Spain)	100.00	(3)
Transmisora Mejillones, S.A.	Quadra 1	Santiago de Chile (Chile)	100.00	(1)
Transmisora Baquedano, S.A.	Quadra 2	Santiago de Chile (Chile)	100.00	(1)

(1) Business sector: Electric transmission lines
(2) Business sector: Efficient natural gas
(3) Business sector: Renewable energy
(4) Business sector: Water
(5) Holding Company
* 100% of Class A shares held by Liberty (US tax equity investor, non-related party).

The Appendices are an integral part of the Notes to the financial statements.

Appendices

Appendix II

Investments recorded under the equity method as of December 31, 2017

Company name	Project name	Registered address	% of nominal share	Business
Evacuacion Valdecaballeros, S.L.	Valdecaballeros	Caceres (Spain)	57.2	(3)
Geida Tlemcen S.L.	Geida Tlemcen	Madrid (Spain)	50.0	(4)
Pectonex R.F.	Pectonex	Pretoria (South Africa)	50.0	(3)
Evacuación Villanueva del Rey, S.L.	Villanueva del Rey	Sevilla (Spain)	40.0	(3)

Investments recorded under the equity method as of December 31, 2016

Company name	Project name	Registered address	% of nominal share	Business
Evacuacion Valdecaballeros, S.L.	Valdecaballeros	Caceres (Spain)	57.2	(3)
Geida Tlemcen S.L.	Geida Tlemcen	Madrid (Spain)	50.0	(4)
Pectonex R.F.	Pectonex	Pretoria (South Africa)	50.0	(3)
Evacuación Villanueva del Rey, S.L.	Villanueva del Rey	Sevilla (Spain)	40.0	(3)

(1) Business sector: Electric transmission lines
(2) Business sector: Efficient natural gas
(3) Business sector: Renewable energy
(4) Business sector: Water
(5) Holding Company

The Appendices are an integral part of the Notes to the consolidated financial statements.

Projects subject to the application of IFRIC 12 interpretation based on the concession of services as of December 31, 2017 and 2016

Description of the Arrangements

Solana

Solana is a 250 MW net (280 MW gross) solar electric generation facility located in Maricopa County, Arizona, approximately 70 miles southwest of Phoenix. Arizona Solar One LLC, or Arizona Solar, owns the Solana project. Solana includes a 22-mile 230kV transmission line and a molten salt thermal energy storage system. The construction of Solana commenced in December 2010 and Solana reached COD on October 9, 2013.

Solana has a 30-year, PPA with Arizona Public Service, or APS, approved by the Arizona Corporation Commission (ACC). The PPA provides for the sale of electricity at a fixed price per MWh with annual increases of 1.84% per year. The PPA includes limitations on the amount and condition of the energy that is received by APS with minimum and maximum thresholds for delivery capacity that must not be breached.

Mojave

Mojave is a 250 MW net (280 MW gross) solar electric generation facility located in San Bernardino County, California, approximately 100 miles northeast of Los Angeles. Abengoa commenced construction of Mojave in September 2011 and Mojave reached COD on December 1, 2014.

Mojave has a 25-year, PPA with Pacific Gas & Electric Company, or PG&E, approved by the California Public Utilities Commission (CPUC). The PPA began on COD. The PPA provides for the sale of electricity at a fixed base price per MWh without any indexation mechanism, including limitations on the amount and condition of the energy that is received by PG&E with minimum and maximum thresholds for delivery capacity that must not be breached.

Palmatir

Palmatir is an on-shore wind farm facility in Uruguay with nominal installed capacity of 50 MW. Palmatir has 25 wind turbines and each turbine has a nominal capacity of 2 MW. UTE (Administracion Nacional de Usinas y Transmisiones Electricas), Uruguay’s state-owned electricity company, has agreed to purchase all energy produced by Palmatir pursuant to a 20-year PPA.

Palmatir reached COD in May 2014. The wind farm is located in Tacuarembo, 170 miles north of the city of Montevideo.

Palmatir signed a PPA with UTE on September 14, 2011 for 100% of the electricity produced, approved by URSEA (Unidad Reguladora de Servicios de Energia y Agua). UTE will pay a fixed-price tariff per MWh under the PPA, which is denominated in U.S. dollars and will be partially adjusted in January of each year according to a formula based on inflation.

Cadonal

Cadonal is an on-shore wind farm facility in Uruguay with nominal installed capacity of 50 MW. Cadonal has 25 wind turbines and each turbine has a nominal capacity of 2 MW each. UTE (Administracion Nacional de Usinas y Trasmisiones Electricas), Uruguay´s state-owned electricity company, has agreed to purchase all energy produced by Cadonal pursuant to a 20-year PPA.

Cadonal reached COD in December 2014. The wind farm is located in Flores, 105 miles north of the city of Montevideo.

Cadonal signed a PPA with UTE on December 28, 2012 for 100% of the electricity produced, approved by URSEA (Unidad Reguladora de Servicios de Energia y Agua). UTE pays a fixed tariff per MWh under the PPA, which is denominated in U.S. dollars and will be adjusted every January considering both U.S. and Uruguay´s inflation indexes and the exchange rate between Uruguayan pesos and U.S. dollars.

Solaben 2 & Solaben 3

The Solaben 2 and Solaben 3 are two 50 MW Concentrating Solar Power facilities and are part of Abengoa's Extremadura Solar Complex. The Extremadura Solar Complex consists of four Concentrating Solar Power plants (Solaben 1, Solaben 2, Solaben 3 and Solaben 6), and is located in the municipality of Logrosan, Spain. Abengoa commenced construction of Solaben 2 and Solaben 3 in August 2010. Solaben 2 reached COD in June 2012 and Solaben 3 reached COD in October 2012. Solaben Electricidad Dos, S.A., or SE2, owns Solaben 2 and Solaben Electricidad Tres, S.A., or SE3, owns Solaben 3.

Renewable energy plants in Spain, like Solaben 2 and Solaben 3, are regulated by the Government through a series of laws and rulings which guarantee the owners of the plants a reasonable remuneration for their investments. Solaben 2 and Solaben 3 sell the power they produce into the wholesale electricity market, where offer and demand are matched and the pool price is determined, and also receive additional payments from the Comision Nacional de los Mercados y de la Competencia, or CNMC, the Spanish state-owned regulator.

Solacor 1 & Solacor 2

The Solacor 1 and Solacor 2 are two 50 MW Concentrating Solar Power facilities and are part of Abengoa's El Carpio Solar Complex, located in the municipality of El Carpio, Spain. The Carpio Solar Complex consists in a conventional parabolic trough Concentrating Solar Power system to generate electricity. Abengoa commenced construction of Solacor 1 and Solacor 2 in September 2010. The COD was reached in two phases, the first one, Solacor 1, was reached in February 2012 and the second one, Solacor 2, was reached in March 2012. JGC Corporation holds 13% of Solacor 1 & Solacor 2, a Japanese engineering company.

Renewable energy plants in Spain, like Solacor 1 and Solacor 2, are regulated by the Government through a series of laws and rulings which guarantee the owners of the plants a reasonable remuneration for their investments. Solacor 1 and Solacor 2 sell the power they produce into the wholesale electricity market, where offer and demand are matched and the pool price is determined, and also receive additional payments from the Comision Nacional de los Mercados y de la Competencia, or CNMC, the Spanish state-owned regulator.

ACT

The ACT plant is a gas-fired cogeneration facility with a rated capacity of approximately 300 MW and between 550 and 800 metric tons per hour of steam. The plant includes a substation and an approximately 52 mile and 115-kilowatt transmission line.

On September 18, 2009, ACT Energy México entered into the Pemex Conversion Services Agreement, or the Pemex CSA, with Petroleos Mexicanos, or Pemex. Pemex is a state-owned oil and gas company supervised by the Comision Reguladora de Energía (CRE), the Mexican state agency that regulates the energy industry. The Pemex CSA has a term of 20 years from the in-service date and will expire on March 31, 2033.

According to the Pemex CSA, ACT must provide, in exchange for a fixed price with escalation adjustments, services including the supply and transformation of natural gas and water into thermal energy and electricity. Part of the electricity is to be supplied directly to a Pemex facility nearby, allowing the Comision Federal de Electricidad (CFE) to supply less electricity to that facility. Approximately 90% of the electricity must be injected into the Mexican electricity network to be used by retail and industrial end customers of CFE in the region. Pemex is then entitled to receive an equivalent amount of energy in more than 1,000 of their facilities in other parts of the country from CFE, following an adjustment mechanism under the supervision of CFE.

The Pemex CSA is denominated in U.S. dollars. The price is a fixed tariff and will be adjusted annually, part of it according to inflation and part according to a mechanism agreed in the contract that on average over the life of the contract reflects expected inflation. The components of the price structure and yearly adjustment mechanisms were prepared by Pemex and provided to bidders as part of the request for proposal documents.

ATN

ATN, or the ATN Project, in Peru is part of the SGT (Sistema Garantizado de Transmision), which includes all transmission line concessions allocated by a bidding process by the government and is comprised of the following facilities:

(i) the approximately 356 mile, 220kV line from Carhuamayo-Paragsha-Conococha-Kiman-Ayllu-Cajamarca Norte;

(ii) the 4.3 mile, 138kV link between the existing Huallanca substation and Kiman Ayllu substations;

(iii) the 1.9 mile, 138kV link between the 138kV Carhuamayo substation and the 220kV Carhuamayo substation;

(iv) the new Conococha and Kiman Ayllu substations; and

(v) the expansion of the Cajamarca Norte, 220kV Carhuamayo, 138kV Carhuamayo and 220kV Paragsha substations.

Pursuant to the initial concession agreement, the Ministry of Energy, on behalf of the Peruvian Government, granted ATN a concession to construct, develop, own, operate and maintain the ATN Project. The initial concession agreement became effective on May 22, 2008 and will expire 30 years after COD of the first tranche of the line, which took place in January 2011. ATN is obliged to provide the service of transmission of electric energy through the operation and maintenance of the electric transmission line, according to the terms of the contract and the applicable law.

The laws and regulations of Peru establish the key parameters of the concession contract, the price indexation mechanism, the rights and obligations of the operator and the procedures that have to be followed in order to fix the applicable tariff, which occurs through a regulated bidding process. Once the bidding process is complete and the operator is granted the concession, the pricing of the power transmission service is established in the concession agreement. ATN has a 30-year concession agreement with a fixed-price tariff base denominated in U.S. dollars that is adjusted annually after COD of each line, in accordance with the U.S. Finished Goods Less Food and Energy Index published by the U.S. Department of Labor.

ATS

ABY Transmision Sur, or ATS Project, in Peru is part of the Guaranteed Transmission System, or (Sistema Garantizado de Transmisión) which includes all transmission line concessions allocated by a bidding process by the government, and is comprised of:

(i) one 500kV electric transmission line and two short 220kV electric transmission lines, which are linked to existing substations;

(ii) three new 500kV substations; and

(iii) three existing substations (two existing 220kV substations and one existing 550/220kV substation), through the development of new transformers, line reactors, series reactive compensation and shunt reactions in some substations.

Pursuant to the initial concession agreement, the Ministry of Energy, on behalf of the Peruvian Government, granted ATS a concession to construct, develop, own, operate and maintain the ATS Project. The initial concession agreement became effective on July 22, 2010 and will expire 30 years after COD, which took place in January 2014. ATS is obliged to provide the service of transmission of electric energy through the operation and maintenance of the electric transmission line, according to the terms of the contract and the applicable law.

The laws and regulations of Peru establish the key parameters of the concession contract, the price indexation mechanism, the rights and obligations of the operator and the procedure that has to be followed in order to fix the applicable tariff, which occurs through a regulated bidding process. Once the bidding process is complete and the operator is granted the concession, the pricing of the power transmission service is established in the concession agreement. ATS has a 30-year concession agreement with fixed-price tariff base denominated in U.S. dollars that is adjusted annually after COD of each line, in accordance with the U.S. Finished Goods Less Food and Energy Index published by the U.S. Department of Labor.

Quadra 1 & Quadra 2

Transmisora Mejillones, or Quadra 1, is a 49-miles transmission line project and Tranmisora Baquedano, or Quadra 2, is a 32-miles transmission line project, each connected to the Sierra Gorda substations.

Both projects have concession agreements with Sierra Gorda SCM. The agreements are denominated in U.S. dollars and are indexed mainly to CPI. The concession agreements each have a 21-year term that began on COD, which took place in April 2014 and March 2014 for Quadra 1 and Quadra 2, respectively.

Quadra 1 and Quadra 2 belong to the Northern Interconnected System (SING), one of the two interconnected systems into which the Chilean electricity market is divided and structured for both technical and regulatory purposes.

As part of the SING, Quadra 1 and Quadra 2 and the service they provide are regulated by several regulatory bodies, in particular: the Superintendent's office of Electricity and Fuels (Superintendencia de Electricidad y Combustibles, SEC), the Economic Local Dispatch Center (Centro de Despacho Economico de Cargas, CDEC), the National Board of Energy (Comision Nacional de Energia, CNE) and the National Environmental Board (Comision Nacional de Medio Ambiente, CONAMA) and other environmental regulatory bodies.

In all these concession arrangements, the operator has all the rights necessary to manage, operate and maintain the assets and the obligation to provide the services defined above, which are clearly defined in each concession contract and in the applicable regulations in each country.

Helioenergy 1&2

The Helioenergy 1/2 project is located in Ecija, Spain. Abengoa started the construction of Helioenergy in 2010, and reached COD in 2011. Since COD, the projects have obtained good generation results achieving systematically year after year results aligned or above the target productions defined.

Helioenergy relies on a Conventional parabolic trough Concentrating Solar Power system to generate electricity. Helioenergy evacuates its electricity through an aerial underground line 220 kV from the substation of the plant to a 220 kV line that ends in SET Villanueva del Rey (owned by Red Eléctrica de España), where the connection point of the plant is located.

Renewable energy plants in Spain, like Helionergy 1 and Helionergy 2, are regulated by the Government through a series of laws and rulings which guarantee the owners of the plants a reasonable remuneration for their investments. Helionergy 1 and Helionergy 2 sell the power they produce into the wholesale electricity market, where offer and demand are matched and the pool price is determined, and also receive additional payments from the Comision Nacional de los Mercados y de la Competencia, or CNMC, the Spanish state-owned regulator.

Helios 1&2

The Helios 1/2 project is a 100 MW Concentrating Solar Power facility known as Plataforma Solar Castilla la Mancha, located in the municipality of Arenas de San Juan, Puerto Lápice and Villarta de San Juan, Spain. Helios 1 COD was reached in 2Q 2012, Helios 2 COD was reached in 3Q 2012. Since COD, the projects have obtained good generation results aligned or above the production targets.

Helios 1/2 relies on a Conventional parabolic trough Concentrating Solar Power system to generate electricity. The technology is identical to the one used at Solaben 2/3 and Solacor 1/2.

Renewable energy plants in Spain, like Helios 1 and Helios 2, are regulated by the Government through a series of laws and rulings which guarantee the owners of the plants a reasonable remuneration for their investments. Helios 1 and Helios 2 sell the power they produce into the wholesale electricity market, where offer and demand are matched and the pool price is determined, and also receive additional payments from the Comision Nacional de los Mercados y de la Competencia, or CNMC, the Spanish state-owned regulator.

Solnova 1,3&4

The Solnova 1/3/4 project is a 150 MW Concentrating Solar Power facility, part of the Sanlucar Solar Platform, located in the municipality of Sanlucar la Mayor, Spain. Solnova 1 COD was reached in 2Q 2010, Solnova 3 COD was reached in 2Q 2010 and Solnova 4 COD was reached in 3Q 2010. Since COD, the projects have obtained good generation results achieving results aligned with the target production numbers.

Solnova 1/3/4 relies on a Conventional parabolic trough Concentrating Solar Power system to generate electricity. The technology is identical to the one used at Solaben 2/3 and Solacor 1/2.

Solnova 1/3/4 evacuates its electricity through an aerial-underground line 66 kV from the substation of the plant to a 220 kV line that ends in SET Casaquemada, where the connection point of the plant is located.

Renewable energy plants in Spain, like Solnova 1, Solnova 3 and Solnova 4, are regulated by the Government through a series of laws and rulings which guarantee the owners of the plants a reasonable remuneration for their investments. Solnova 1, Solnova 3 and Solnova 4 sell the power they produce into the wholesale electricity market, where offer and demand are matched and the pool price is determined, and also receive additional payments from the Comision Nacional de los Mercados y de la Competencia, or CNMC, the Spanish state-owned regulator.

Honaine

The Honaine project is a water desalination plant located in Taffsout, Algeria, near three important cities: Oran, to the northeast, and Sidi Bel Abbés and Tlemcen, to the southeast. Myah Bahr Honaine Spa, or MBH, is the vehicle incorporated in Algeria for the purposes of owning the Honaine project. Algerian Energy Company, SPA, or AEC, owns 49% and Valoriza Agua S.L., a subsidiary of Sacyr, S.A., owns the remaining 25.5% of the Honaine project.

AEC is the Algerian agency in charge of delivering Algeria’s large-scale desalination program. It is a joint venture set up in 2001 between the national oil and gas company, Sonatrach, and the national gas and electricity company, Sonelgaz. Each of Sonatrach and Sonelgaz owns 50% of AEC.

The technology selected for the Honaine plant is currently the most commonly used in this kind of project. It consists of desalination using membranes by reverse osmosis. Honaine has a capacity of seven M ft3 per day of desalinated water and it is under operation since July 2012. The project represents approximately 9.0% of Algeria’s total desalination capacity and serves a population of 1.0 million.

The water purchase agreement is a U.S. dollar indexed 25-year take-or-pay contract with Sonatrach / Algérienne des Eaux, or ADE. The tariff structure is based upon plant capacity and water production, covering variable cost (water cost plus electricity cost). Tariffs are adjusted monthly based on the indexation mechanisms that include local inflation, U.S. inflation and the exchange rate between the U.S. dollar and local currency.

Skikda

The Skikda project is a water desalination plant located in Skikda, Algeria. Skikda is located 510 km east of Alger. Aguas de Skikda, or ADS, is the vehicle incorporated in Algeria for the purposes of owning the Skikda project. AEC owns 49% and Valoriza Agua S.L. owns the remaining 16.83% of the Skikda project.

AEC is the Algerian agency in charge of delivering Algeria's large-scale desalination program. It is a joint venture set up in 2001 between the national oil and gas company, Sonatrach, and the national gas and electricity company, Sonelgaz. Each of Sonatrach and Sonelgaz owns 50% of AEC.

The technology selected for the Skikda plant is currently the most commonly used in this kind of project. It consists of the use of membranes to obtain desalinated water by reverse osmosis. Skikda has a capacity of 3.5 M ft3 per day of desalinated water and is in operation since February 2009. The project represents approximately 4.5% of Algeria's total desalination capacity and serves a population of 0.5 million.

The water purchase agreement is a U.S. dollar indexed 25-year take-or-pay contract with Sonatrach / ADE. The tariff structure is based upon plant capacity and water production, covering variable cost (water cost plus electricity cost). Tariffs are adjusted monthly based on the indexation mechanisms that include local inflation, U.S. inflation and the exchange rate between the U.S. dollar and local currency.

ATN 2

ATN 2, in Peru, is part of the Complementary Transmission System, or Sistema Complementario de Transmision, SCT, and is comprised of the following facilities:

(i) The approximately 130km, 220kV line from SE Cotaruse to Las Bambas;

(ii) The connection to the gate of Las Bambas Substation

(iii) The expansion of the Cotaruse 220kV substation (works assigned to Consorcio Transmantaro)

The Client is Las Bambas Mining Company, a company owned by a partnership conformed by a subsidiary of China Minmetals Corporation (62.5%), a wholly owned subsidiary of Guoxin International Investment Co. Ltd (22.5%) and CITIC Metal Co. Ltd (15.0%). China Minmetals Corporation is the fifth largest metals company included in the Fortune Global 500 list.

Abengoa started the permitting phase of ATN2 Project in May 2011; and the plant reached COD during May 2015.

The ATN2 Project has a 18-year contract period, after that, ATN2 assets will remain as property of the SPV and therefore it is likely a new contract could be negotiated. The ATN2 Project has a fixed-price tariff base denominated in U.S. dollars, partially adjusted annually in accordance with the U.S. Finished Goods Less Food and Energy Index as published by the U.S. Department of Labor. The receipt of the tariff base is independent from the effective utilization of the transmission lines and substations related to the ATN2 Project. The tariff base is intended to provide the ATN2 Project with consistent and predictable monthly revenues sufficient to cover the ATN2 Project's operating costs and debt service and to earn an equity return. Peruvian law requires the existence of a definitive concession agreement to perform electricity transmission activities where the transmission facilities cross public land or land owned by third parties. On May 31, 2014, the Ministry of Energy granted the project a definitive concession agreement to the transmission lines of the ATN2 Project.

Kaxu

Kaxu Solar One, or Kaxu, is a 100MW solar Conventional Parabolic Trough Project located in Paulputs in the Northern Cape Province of South Africa, approximately 30 km north east of the small town of Pofadder. Atlantica Yield, through Abengoa Solar South Africa (Pty) Ltd., owns 51% of the Kaxu Project. The Project Company, named Kaxu Solar One (Pty) Ltd., is owned by a consortium composed by Abengoa Solar South Africa (51%), Industrial Development Corporation of South Africa (29%) and Kaxu Community Trust (20%).

The project reached COD in February 2015.

Kaxu has a 20-year PPA with Eskom SOC Ltd., or Eskom, under a take or pay contract for the purchase of electricity up to the contracted capacity from the facility. Eskom purchases all the output of the Kaxu Plant under a fixed price formula in local currency subject to indexation to local inflation which protects the Company from potential devaluation over the long term. Being the project COD February 2015, the PPA expires on February 2035.

Solaben 1&6

The Solaben 1&6 is a 100MW Concentrated Solar Power facility part of the Extremadura Solar Platform, located in the municipality of Logrosán, Spain. Solaben 1/6 COD was reached on September 1, 2013. Since COD, the projects have obtained good generation aligned with the target production figures.

Solaben 1&6 relies on a Conventional Parabolic through Concentrating Solar Power system to generate electricity. The technology is identical to the one used at Solaben 2/3 and Solacor 1/2 projects.

Renewable energy plants in Spain, like Solaben 1 and Solaben 6, are regulated by the Government through a series of laws and rulings which guarantee the owners of the plants a reasonable remuneration for their investments. Solaben 1 and Solaben 6 sell the power they produce into the wholesale electricity market, where offer and demand are matched and the pool price is determined, and also receive additional payments from the Comisión Nacional de los Mercados y de la Competencia, or CNMC, the Spanish state-owned regulator.

Projects subject to the application of IFRIC 12 interpretation based on the concession of services as of December 31, 2017

Project name	Country	Status(1)	% of Nominal Share(2)	Period of Concession(4) (5)	Offtaker(7)	Financial/ Intangible(3)	Assets/ Investment	Accumulated Amortization	Operating Profit/ (Loss)(8)	Arrangement Terms (price)	Description of the Arrangement
Renewable energy:											
Solana	USA	(O)	100.0	30 Years	APS	(I)	1,993,171	(275,591)	11,795	Fixed price per MWh with annual increases of 1.84% per year	30-year PPA with APS regulated by ACC
Mojave	USA	(O)	100.0	25 Years	PG&E	(I)	1,585,219	(193,029)	50,160	Fixed price per MWh without any indexation mechanism	25-year PPA with PG&E regulated by CPUC and CAEC
Palmatir	Uruguay	(O)	100.0	20 Years	UTE, Uruguay Administration	(I)	146,274	(29,495)	5,767	Fixed price per MWh in USD with annual increases based on inflation	20-year PPA with UTE, Uruguay state-owned utility
Cadonal	Uruguay	(O)	100.0	20 Years	UTE, Uruguay Administration	(I)	120,411	(33,682)	3,711	Fixed price per MWh in USD with annual increases based on inflation	20-year PPA with UTE, Uruguay state-owned utility
Solaben 2	Spain	(O)	70.0	25 Years	Kingdom of Spain	(I)	326,074	(48,837)	14,274	Regulated revenue base(6)	Regulated revenue established by different laws and rulings in Spain
Solaben 3	Spain	(O)	70.0	25 Years	Kingdom of Spain	(I)	326,203	(51,242)	14,725	Regulated revenue base(6)	Regulated revenue established by different laws and rulings in Spain
Solacor 1	Spain	(O)	87.0	25 Years	Kingdom of Spain	(I)	324,854	(56,034)	13,686	Regulated revenue base(6)	Regulated revenue established by different laws and rulings in Spain
Solacor 2	Spain	(O)	87.0	25 Years	Kingdom of Spain	(I)	336,510	(57,130)	13,324	Regulated revenue base(6)	Regulated revenue established by different laws and rulings in Spain
Solnova 1	Spain	(O)	100.0	25 Years	Kingdom of Spain	(I)	333,779	(76,622)	18,325	Regulated revenue base(6)	Regulated revenue established by different laws and rulings in Spain

Solnova 3	Spain	(O)	100.0	25 Years	Kingdom of Spain	(I)	313,593	(69,392)	19,054	Regulated revenue base[6]	Regulated revenue established by different laws and rulings in Spain
Solnova 4	Spain	(O)	100.0	25 Years	Kingdom of Spain	(I)	291,151	(63,617)	18,227	Regulated revenue base[6]	Regulated revenue established by different laws and rulings in Spain
Helios 1	Spain	(O)	100.0	25 Years	Kingdom of Spain	(I)	329,823	(52,625)	11,127	Regulated revenue base[6]	Regulated revenue established by different laws and rulings in Spain
Helios 2	Spain	(O)	100.0	25 Years	Kingdom of Spain	(I)	321,018	(49,606)	12,038	Regulated revenue base[6]	Regulated revenue established by different laws and rulings in Spain

Helioenergy 1	Spain	(O)	100.0	25 Years	Kingdom of Spain	(I)	324,738	(56,101)	17,601	Regulated revenue base(6)	Regulated revenue established by different laws and rulings in Spain
Helioenergy 2	Spain	(O)	100.0	25 Years	Kingdom of Spain	(I)	325,472	(53,243)	17,972	Regulated revenue base(6)	Regulated revenue established by different laws and rulings in Spain
Solaben 1	Spain	(O)	100.0	25 Years	Kingdom of Spain	(I)	316,797	(39,172)	14,672	Regulated revenue base(6)	Regulated revenue established by different laws and rulings in Spain
Solaben 6	Spain	(O)	100.0	25 Years	Kingdom of Spain	(I)	313,677	(38,720)	14,112	Regulated revenue base(6)	Regulated revenue established by different laws and rulings in Spain
Kaxu	South Africa	(O)	51.0	20 Years	Eskom	(I)	604,898	(87,482)	29,991	Take or pay contract for the purchase of electricity up to the contracted capacity from the facility.	20-year PPA with Eskom SOC Ltd. With a fixed price formula in local currency subject to indexation to local inflation
Efficient natural gas:											
ACT	Mexico	(O)	100.0	20 Years	Pemex	(F)	660,432	-	110,208	Fixed price to compensate both investment and O&M costs, established in USD and adjusted annually partially according to inflation and partially according to a mechanism agreed in contract	20-year Services Agreement with Pemex, Mexican oil & gas state-owned company

Electric transmission lines:											
ATS	Peru	(O)	100	30 Years	Republic of Peru	(I)	531,209	(68,700)	24,496	Tariff fixed by contract and adjusted annually in accordance with the US Finished Goods Less Food and Energy inflation index	30-year Concession Agreement with the Peruvian Government
ATN	Peru	(O)	100	30 Years	Republic of Peru	(I)	319,875	(70,611)	2,725	Tariff fixed by contract and adjusted annually in accordance with the US Finished Goods Less Food and Energy inflation index	30-year Concession Agreement with the Peruvian Government
Quadra I	Chile	(O)	100	21 Years	Sierra Gorda	(F)	41,583	-	4,811	Fixed price in USD with annual adjustments indexed mainly to US CPI	21-year Concession Contract with Sierra Gorda regulated by CDEC and the Superentendencia de Electricidad, among others
Quadra II	Chile	(O)	100	21 Years	Sierra Gorda	(F)	55,480	-	6,434	Fixed price in USD with annual adjustments indexed mainly to US CPI	21-year Concession Contract with Sierra Gorda regulated by CDEC and the Superentendencia de Electricidad, among others
ATN 2	Peru	(O)	100	18 Years	Las Bambas Mining	(F)	83,851	-	12,477	Fixed-price tariff base denominated in U.S. dollars with Las Bambas	18 years purchase agreement
Water:											
Skikda	Argelia	(O)	34.2	25 Years	Sonatrach & ADE	(F)	90,326	-	16,908	U.S. dollar indexed take-or-pay contract with Sonatrach / ADE	25 years purchase agreement
Honaine	Argelia	(O)	25.5	25 Years	Sonatrach & ADE	(F)	N/A[9]	N/A[9]	N/A[9]	U.S. dollar indexed take-or-pay contract with Sonatrach / ADE	25 years purchase agreement

(1) In operation (O), Construction (C) as of December 31, 2017.
(2) Liberty Interactive Corporation agreed to invest $300 million in Class A membership interests in exchange for a share of the dividends and the taxable loss generated by Solana on October 2, 2013. Itochu Corporation holds 30% of the economic rights to each of Solaben 2 and Solaben 3. JGC Corporation holds 13% of the economic rights to each Solacor 1 and Solacor 2. Algerian Energy Company, SPA, or AEC, owns 49% and Valoriza Agua, S.L., a subsidiary of Sacyr, S.A., owns the remaining 25.5% of the Honaine project. AEC owns 49% and Valoriza Agua S.L. owns the remaining 16.83% of the Skikda project. Industrial Development Corporation of South Africa (29%) & Kaxu Community Trust (20%) for the Kaxu Project
(3) Classified as concessional financial asset (F) or as intangible assets (I).
(4) The infrastructure is used for its entire useful life. There are no obligations to deliver assets at the end of the concession periods, except for ATN and ATS.
(5) Generally, there are no termination provisions other than customary clauses for situations such as bankruptcy or fraud from the operator, for example.
(6) Sales to wholesale markets and additional fixed payments established by the Spanish government.
(7) In each case the offtaker is the grantor.
(8) Figures reflect the contribution to the consolidated financial statements of Atlantica Yield Plc. as of December 31, 2017.
(9) Recorded under the equity method.

The Appendices are an integral part of the Notes to the consolidated financial statements.

Projects subject to the application of IFRIC 12 interpretation based on the concession of services as of December 31, 2016

Project name	Country	Status(1)	% of Nominal Share(2)	Period of Concession(4)(5)	Offtaker(7)	Financial/ Intangible(3)	Assets/ Investment	Accumulated Amortization	Operating Profit/ (Loss)(8)	Arrangement Terms (price)	Description of the Arrangement
Renewable energy:											
Solana	USA	(O)	100.0	30 Years	APS	(I)	2,034,335	(215,987)	7,324	Fixed price per MWh with annual increases of 1.84% per year	30-year PPA with APS regulated by ACC
Mojave	USA	(O)	100.0	25 Years	PG&E	(I)	1,585,159	(130,348)	50,460	Fixed price per MWh without any indexation mechanism	25-year PPA with PG&E regulated by CPUC and CAEC
Palmatir	Uruguay	(O)	100.0	20 Years	UTE, Uruguay Administration	(I)	146,274	(22,362)	1,238	Fixed price per MWh in USD with annual increases based on inflation	20-year PPA with UTE, Uruguay state-owned utility
Cadonal	Uruguay	(O)	100.0	20 Years	UTE, Uruguay Administration	(I)	120,411	(28,616)	(14,443)	Fixed price per MWh in USD with annual increases based on inflation	20-year PPA with UTE, Uruguay state-owned utility
Solaben 2	Spain	(O)	70.0	25 Years	Kingdom of Spain	(I)	286,577	(34,792)	11,128	Regulated revenue base(6)	Regulated revenue established by different laws and rulings in Spain
Solaben 3	Spain	(O)	70.0	25 Years	Kingdom of Spain	(I)	286,824	(37,014)	12,536	Regulated revenue base(6)	Regulated revenue established by different laws and rulings in Spain

Solacor 1	Spain	(O)	87.0	25 Years	Kingdom of Spain	(I)	284,835	(41,011)	12,327	Regulated revenue base(6)	Regulated revenue established by different laws and rulings in Spain
Solacor 2	Spain	(O)	87.0	25 Years	Kingdom of Spain	(I)	295,146	(41,688)	12,008	Regulated revenue base(6)	Regulated revenue established by different laws and rulings in Spain
Solnova 1	Spain	(O)	100.0	25 Years	Kingdom of Spain	(I)	292,417	(58,869)	16,975	Regulated revenue base(6)	Regulated revenue established by different laws and rulings in Spain
Solnova 3	Spain	(O)	100.0	25 Years	Kingdom of Spain	(I)	274,736	(53,280)	15,168	Regulated revenue base(6)	Regulated revenue established by different laws and rulings in Spain
Solnova 4	Spain	(O)	100.0	25 Years	Kingdom of Spain	(I)	255,078	(48,649)	16,333	Regulated revenue base(6)	Regulated revenue established by different laws and rulings in Spain
Helios 1	Spain	(O)	100.0	25 Years	Kingdom of Spain	(I)	289,739	(38,111)	12,935	Regulated revenue base(6)	Regulated revenue established by different laws and rulings in Spain
Helios 2	Spain	(O)	100.0	25 Years	Kingdom of Spain	(I)	282,015	(35,631)	12,755	Regulated revenue base(6)	Regulated revenue established by different laws and rulings in Spain

Helioenergy 1	Spain	(O)	100.0	25 Years	Kingdom of Spain	(I)	284,492	(41,603)	14,087	Regulated revenue base(6)	Regulated revenue established by different laws and rulings in Spain
Helioenergy 2	Spain	(O)	100.0	25 Years	Kingdom of Spain	(I)	285,288	(39,025)	14,354	Regulated revenue base(6)	Regulated revenue established by different laws and rulings in Spain
Solaben 1	Spain	(O)	100.0	25 Years	Kingdom of Spain	(I)	277,563	(26,392)	11,952	Regulated revenue base(6)	Regulated revenue established by different laws and rulings in Spain
Solaben 6	Spain	(O)	100.0	25 Years	Kingdom of Spain	(I)	274,643	(26,090)	12,358	Regulated revenue base(6)	Regulated revenue established by different laws and rulings in Spain
Kaxu	South Africa	(O)	51.0	20 Years	Eskom	(I)	546,861	(52,126)	36,708	Take or pay contract for the purchase of electricity up to the contracted capacity from the facility.	20-year PPA with Eskom SOC Ltd. With a fixed price formula in local currency subject to indexation to local inflation
Efficient natural gas:											
ACT	Mexico	(O)	100.0	20 Years	Pemex	(F)	646,962	-	110,792	Fixed price to compensate both investment and O&M costs, established in USD and adjusted annually partially according to inflation and partially according to a mechanism agreed in contract	20-year Services Agreement with Pemex, Mexican oil & gas state-owned company

Electric transmission lines:											
ATS	Peru	(O)	100	30 Years	Republic of Peru	(I)	530,871	(51,019)	25,610	Tariff fixed by contract and adjusted annually in accordance with the US Finished Goods Less Food and Energy inflation index	30-year Concession Agreement with the Peruvian Government
ATN	Peru	(O)	100	30 Years	Republic of Peru	(I)	319,958	(59,839)	1,134	Tariff fixed by contract and adjusted annually in accordance with the US Finished Goods Less Food and Energy inflation index	30-year Concession Agreement with the Peruvian Government
Quadra I	Chile	(O)	100	21 Years	Sierra Gorda	(F)	41,595	-	4,188	Fixed price in USD with annual adjustments indexed mainly to US CPI	21-year Concession Contract with Sierra Gorda regulated by CDEC and the Superentendencia de Electricidad, among others
Quadra II	Chile	(O)	100	21 Years	Sierra Gorda	(F)	55,417	-	5,049	Fixed price in USD with annual adjustments indexed mainly to US CPI	21-year Concession Contract with Sierra Gorda regulated by CDEC and the Superentendencia de Electricidad, among others
ATN 2	Peru	(O)	100	18 Years	Las Bambas Mining	(F)	86,238	-	14,497	Fixed-price tariff base denominated in U.S. dollars with Las Bambas	18 years purchase agreement
Water:											
Skikda	Argelia	(O)	34.2	25 Years	Sonatrach & ADE	(F)	93,170	-	14,416	U.S. dollar indexed take-or-pay contract with Sonatrach / ADE	25 years purchase agreement
Honaine	Argelia	(O)	25.5	25 Years	Sonatrach & ADE	(F)	N/A[9]	N/A[9]	N/A[9]	U.S. dollar indexed take-or-pay contract with Sonatrach / ADE	25 years purchase agreement

(1) In operation (O), Construction (C) as of December 31, 2016.
(2) Liberty Interactive Corporation agreed to invest $300 million in Class A membership interests in exchange for a share of the dividends and the taxable loss generated by Solana on October 2, 2013. Itochu Corporation holds 30% of the economic rights to each of Solaben 2 and Solaben 3. JGC Corporation holds 13% of the economic rights to each Solacor 1 and Solacor 2. Algerian Energy Company, SPA, or AEC, owns 49% and Valoriza Agua, S.L., a subsidiary of Sacyr, S.A., owns the remaining 25.5% of the Honaine project. AEC owns 49% and Valoriza Agua, S.L. owns the remaining 16.83% of the Skikda project. Industrial Development Corporation of South Africa (29%) & Kaxu Community Trust (20%) for the Kaxu Project
(3) Classified as concessional financial asset (F) or as intangible assets (I).
(4) The infrastructure is used for its entire useful life. There are no obligations to deliver assets at the end of the concession periods, except for ATN and ATS.
(5) Generally, there are no termination provisions other than customary clauses for situations such as bankruptcy or fraud from the operator, for example.
(6) Sales to wholesale markets and additional fixed payments established by the Spanish government.
(7) In each case the offtaker is the grantor.
(8) Figures reflect the contribution to the consolidated financial statements of Atlantica Yield Plc. as of December 31, 2016.
(9) Recorded under the equity method.

The Appendices are an integral part of the Notes to the consolidated financial statements.

Appendix IV

Additional Information of Subsidiaries including material Non-controlling interest as of December 31, 2017

Subsidiary name	Non-controlling interests name	% of non-controlling interests held	Dividends paid to non-controlling interests	Profit/(Loss) of non-controlling interests in AY consolidated net result 2017	Non-controlling interests in AY consolidated equity as of December 31, 2017	Non-current assets*	Current Assets*	Non-current liabilities*	Current liabilities*	Net Profit /(Loss)*	Total Comprehensive income*
Kaxu Solar One (Pty) Ltd.	Industrial Development Corporation of South Africa (IDC)	29%	-	(5,678)	1,885	526,518	67,294	569,634	20,241	(11,496)	(7,178)
	Kaxu Community Trust	20%									
Aguas de Skikda S.P.A.	Algerian Energy Company S.P.A.	49%**	1,834	8,358	51,232	90,524	31,247	30,145	7,216	9,961	-

* Stand-alone figures as of December 31, 2017

** Atlantica Yield Plc. owns 67% of the shares in Geida Skikda, S.L., which in its turn owns 51% of Aguas de Skikda S.P.A., so that indirectly Atlantica Yield Plc. owns 34.17% of Aguas de Skikda S.P.A. The table only shows information related to the Non-Controlling interests of the SPV, Aguas de Skikda S.P.A.

Additional Information of Subsidiaries including material Non-controlling interest as of December 31, 2016

Subsidiary name	Non-controlling interests name	% of non-controlling interests held	Dividends paid to non-controlling interests	Profit/(Loss) of non-controlling interests in AY consolidated net result 2016	Non-controlling interests in AY consolidated equity as of December 31, 2016	Non-current assets*	Current Assets*	Non-current liabilities*	Current liabilities*	Net Profit /(Loss)*	Total Comprehensive income*
Kaxu Solar One (Pty) Ltd.	Industrial Development Corporation of South Africa (IDC)	29%	-	(3,244)	8,529	495,946	54,717	111,264	421,993	(7,513)	(4,744)
	Kaxu Community Trust	20%									
Aguas de Skikda S.P.A.	Algerian Energy Company S.P.A.	49%**	4,141	7,284	47,796	96,052	29,769	36,591	7,304	13,800	-

* Stand-alone figures as of December 31, 2016

** Atlantica Yield Plc. owns 67% of the shares in Geida Skikda, S.L., which in its turn owns 51% of Aguas de Skikda S.P.A., so that indirectly Atlantica Yield Plc. owns 34.17% of Aguas de Skikda S.P.A. The table only shows information related to the Non-Controlling interests of the SPV, Aguas de Skikda S.P.A.

Appendix V (Schedule I)

Condensed Financial Statements of Atlantica Yield plc

Condensed statements of financial position of Atlantica Yield Plc.

– Amounts in thousands of usd –

	As of December 31,	
	2017	**2016**
Assets		
Investment in affiliates	2,044,967	2,035,598
Loans to affiliates	647,911	704,916
Cash and cash equivalents	148,525	122,154
Other assets	3,704	23,936
Total assets	2,845,107	2,886,604
Liabilities and Equity		
Borrowings	386,616	412,839
Notes and bonds	256,468	255,362
Intercompany liabilities	103,796	54,687
Other Liabilities	11,168	10,296
Total Liabilities	758,048	733,184
Common Stock	10,022	10,022
Additional paid-in capital	1,981,881	1,981,881
Distributable reserves	42,410	116,375
Other reserves	181	13,879
Accumulated gains (losses)-net	52,565	31,263
Total shareholders's equity	2,087,059	2,153,420
Total liabilities and equities	2,845,107	2,886,604

Condensed income statements of Atlantica Yield, Plc.
– Amounts in thousands of usd –

	For the year ended December 31,		
	2017	2016	2015
Income from			
Services	123,944	114,653	65,170
Other financial income	17,419	8	194
Total income	141,363	114,661	65,364
Expenses			
Other operating expenses	(21,173)	(26,132)	(10,005)
Interest	(46,292)	(35,615)	(27,783)
Other financial expenses	(21,333)	(21,651)	(246,982)
Total expenses	(88,798)	(83,398)	(284,770)
Income/(Loss) before income taxes	52,565	31,263	(219,406)
Income tax benefits/(expense)	-	-	(209)
Profit/(Loss) for the year	52,565	31,263	(219,615)

Other comprehensive income statement of Atlantica Yield, Plc.
– Amounts in thousands of usd –

	For the year ended December 31,		
	2017	**2016**	**2015**
Profit/(loss) for the year	**52,565**	**31,263**	**(219,615)**
Items that may be subject to transfer to income statement			
Change in fair value of cash flow hedges	(13,666)	7,213	3,683
Net income/(expenses) recognized directly in equity	**(13,666)**	**7,213**	**3,683**
Cash flow hedges	(32)	2,321	662
Transfer to income statement	**(32)**	**2,321**	**662**
Other comprehensive income/(loss) for the year	**(13,698)**	**9,534**	**4,345**
Total comprehensive income/(loss) for the year	**38,867**	**40,797**	**(215,270)**

Condensed cash flow statements of Atlantica Yield, Plc.
– Amounts in thousands of usd –

	For the year ended December 31,		
	2017	**2016**	**2015**
Cash Flow from operating activities	34,937	5,911	(15,943)
Cash Flow—investing activities			
Decrease (increase) in investment and advance to affiliates	151,033	97,341	(939,503)
Net decrease (increase) in other assets	-	-	(157)
Cash (used for)/provided by investing activities	151,033	97,341	(939,660)
Cash Flow—financing activities			
Net increase/(decrease) in borrowings and other liabilities	(64,754)	-	310,462
Dividend paid to shareowner	(94,845)	(26,585)	(128,859)
Capital increase and other	-	-	664,120
Cash from financing activities	(159,599)	(26,585)	845,723
Increase (decrease) in cash and cash equivalents during the year	26,371	76,667	(109,880)
Cash and cash equivalent at the beginning of the year	122,154	45,487	155,367
Cash and cash equivalent at the end of the year	148,525	122,154	45,487

Notes to the Condensed Financial Statements

Schedule I has been provided pursuant to the requirements of Rule 12- 04(a) of Regulation S-X, of the US Securities and Exchange Commission (SEC) which require condensed financial information as to the financial position, change in financial position, results of operations of Atlantica Yield plc, other comprehensive income statement and cash flow statement as of the same dates and for the same periods for which audited consolidated financial statements have been presented when the restricted net assets of consolidated subsidiaries exceed 25 percent of consolidated net assets as of the end of the most recently completed fiscal year.

Certain information and footnote disclosures normally included in financial statements prepared in accordance with International Financial Reporting Standards have been condensed or omitted. The footnote disclosures contain supplemental information only and, as such, these statements should be read in conjunction with the notes to the accompanying consolidated financial statements.

Basis of Presentation.

a) The presentation of Atlantica Yield plc stands alone condensed financial statement has been prepared using the same accounting policies as set out in the accompanying consolidated financial statements except that, the Company records its investment in subsidiaries under the cost method of accounting and that financial income from credits to companies in the group are recorded under Income from services, given that the company is a holding and this type of service is part of its primary activity. Such investments are presented on the statements of financial position as “Investment in and loans to affiliates” at cost less any identified impairment loss.

b) As of December 31, 2017, 2016 and 2015 there were no material contingencies, significant provisions of long-term obligations, mandatory dividend or redemption requirements of redeemable stocks or guarantees of the Company, except for those which have been separately disclosed in the Consolidated Financial Statements, if any.

c) For the year ended December 31, 2017, 2016 and 2015, cash dividend of $10,383 thousand, $29,737 thousand and $18,400 thousand were declared to the Company by its consolidated subsidiaries or associates, respectively.

Reconciliation of the stand-alone to consolidated financial statements of Atlantica Yield Plc.

Profit/(Loss) Reconciliation	**For the year ended December 31,**		
	2017	**2016**	**2015**
Stand-alone—IFRS profit/(loss) for the period	52,565	31,263	(219,615)
Additional profit/(loss) if subsidiaries had been accounted for using the equity method of accounting as opposed to cost method	(164,369)	(36,118)	10,610
Consolidated IFRS profit/(loss) for the period attributable to Atlantica Yield plc	(111,804)	(4,855)	(209,005)

Equity Reconciliation	**As of December 31,**		
	2017	**2016**	**2015**
Stand-alone—IFRS shareholders equity	2,087,059	2,153,420	2,158,021
Additional shareholders equity if subsidiaries had been accounted for using the equity method of accounting as opposed to cost method	(191,606)	(194,309)	(134,520)
Consolidated IFRS shareholders equity	1,895,453	1,959,111	2,023,501

Exhibit 8.1

Subsidiaries of Atlantica Yield plc

Subsidiary	Jurisdiction of Incorporation or Organization
ACT Energy Mexico, S. de R.L. de C.V.	Mexico
ABY Infraestructuras, S.L.	Spain
ABY Infrastructures USA LLC	Arizona
ABY Concessions Infrastructures, S.L.U	Spain
ABY Concessions Peru, S.A.	Peru
ASHUSA Inc.	Delaware
ABY South Africa (Pty) Ltd	South Africa
ASUSHI Inc.	Delaware
ATN, S.A.	Peru
ABY Transmision Sur, S.A.	Peru
ACT Holding S.A. de C.V.	Mexico
Aguas de Skikda S.A.P.	Algeria
Arizona Solar One LLC	Delaware
ASO Holdings Company LLC	Delaware
ATN2, S.A.	Peru
Cadonal, S.A.	Uruguay
Carpio Solar Inversiones, S.A.	Spain
Ecija Solar Inversiones, S.A	Spain
Extremadura Equity Investments Sárl.	Luxembourg
Evacuacion Valdecaballeros, S.L.	Spain
Evacuacion Villanueva del Rey, S.L	Spain
Fotovoltaica Solar Sevilla, S.A.	Spain
Geida Skikda, S.L.	Spain
Helioenergy Electricidad Uno, S.A.	Spain
Helioenergy Electricidad Dos, S.A.	Spain
Helios I Hyperion Energy Investments, S.L.	Spain
Helios II Hyperion Energy Investments, S.L.	Spain
Holding de Energia Eolica S.A.	Uruguay
Hypesol Energy Holding, S.L.	Spain
Kaxu Solar One (Pty) Ltd.	South Africa
Logrosan Equity Investments Sárl.	Luxembourg
Logrosan Solar Inversiones, S.A	Spain
Logrosan Solar Inversiones Dos, S.L	Spain
Miyah Bahr Honaine S.A.P.	Algeria
Mojave Solar Holdings LLC	Delaware
Mojave Solar LLC	Delaware
Palmatir, S.A.	Uruguay
Palmucho, S.A.	Chile
Pectonex, R.F. Proprietary Limited	South Africa
RRHH Servicios Corporativos	Mexico
Sanlucar Solar, S.A.	Spain
Solaben Electricidad Uno S.A.	Spain
Solaben Electricidad Dos, S.A.	Spain
Solaben Electricidad Tres, S.A.	Spain
Solaben Electricidad Seis, S.A.	Spain
Solaben Luxembourg S.A.	Luxembourg
Solacor Electricidad Uno, S.A.	Spain
Solacor Electricidad Dos, S.A.	Spain
ABY Servicios Corporativos S.A.	Spain
Solar Processes, S.A.	Spain
Solnova Solar Inversiones, S.A.	Spain
Solnova Electricidad, S.A	Spain
Solnova Electricidad Tres, S.A.	Spain
Solnova Electricidad Cuatro, S.A.	Spain
Transmisora Mejillones, S.A	Chile
Transmisora Baquedano, S.A.	Chile

Exhibit 12.1

ATLANTICA YIELD PLC

Sarbanes Oxley Certification under Section 302 of the Act

Certification

I, Santiago Seage, Chief Executive Officer of Atlantica Yield plc (the "Company") certify that:

1. I have reviewed this annual report on Form 20-F (the "Annual Report") of the Company;

2. Based on my knowledge, this Annual Report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this Annual Report;

3. Based on my knowledge, the financial statements, and other financial information included in this Annual Report, fairly present in all material respects the financial condition, results of operations and cash flows of the Company as of, and for, the periods presented in this Annual Report;

4. The Company's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the Company and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the company, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this Annual Report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the Company's disclosure controls and procedures and presented in this Annual Report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this Annual Report based on such evaluation; and

(d) Disclosed in this Annual Report any change in the Company's internal control over financial reporting that occurred during the period covered by this Annual Report that has materially affected, or is reasonably likely to materially affect, the Company's internal control over financial reporting; and

5. The Company's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the Company's auditors and the audit committee of Company's board of directors (or persons performing the equivalent function):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the Company's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the Company's internal control over financial reporting.

Date: March 7, 2018

/s/ Santiago Seage

Name: Santiago Seage
Title: Chief Executive Officer

[Signature Page to CEO's Section 302 Certification]

Exhibit 12.2

ATLANTICA YIELD PLC

Sarbanes Oxley Certification under Section 302 of the Act

Certification

I, Francisco Martinez-Davis, Chief Financial Officer of Atlantica Yield plc (the "Company") certify that:

1. I have reviewed this annual report on Form 20-F (the "Annual Report") of the Company;

2. Based on my knowledge, this Annual Report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this Annual Report;

3. Based on my knowledge, the financial statements, and other financial information included in this Annual Report, fairly present in all material respects the financial condition, results of operations and cash flows of the Company as of, and for, the periods presented in this Annual Report;

4. The Company's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the Company and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the company, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this Annual Report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the Company's disclosure controls and procedures and presented in this Annual Report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this Annual Report based on such evaluation; and

(d) Disclosed in this Annual Report any change in the Company's internal control over financial reporting that occurred during the period covered by this Annual Report that has materially affected, or is reasonably likely to materially affect, the Company's internal control over financial reporting; and

5. The Company's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the Company's auditors and the audit committee of Company's board of directors (or persons performing the equivalent function):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the Company's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the Company's internal control over financial reporting.

Date: March 7, 2018

/s/ Francisco Martinez-Davis
Name: Francisco Martinez-Davis
Title: Chief Financial Officer

[Signature Page to CFO's Section 302 Certification]

Exhibit 13.1

Certification Pursuant to 18 U.S.C. Section 1350 as Adopted Pursuant to Section 906 of the Sarbanes Oxley Act of 2002

The certification set forth below is being submitted in connection with the Annual Report on Form 20-F for the year ended December 31, 2017 (the "Annual Report") for the purpose of complying with Rule 13a-14(b) or Rule 15d-14(b) of the Securities Exchange Act of 1934 (the "Exchange Act") and Section 1350 of Chapter 63 of Title 18 of the United States Code.

Santiago Seage and Francisco Martinez-Davis, each certifies that, to the best of his knowledge:

1. The Annual Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2. The information contained in the Annual Report fairly presents, in all material respects, the financial condition and results of operations of the Atlantica Yield plc.

Date: March 7, 2018

By:

	/s/ Santiago Seage
Name:	Santiago Seage
Title:	Chief Executive Officer

By:

	/s/ Francisco Martinez-Davis
Name:	Francisco Martinez-Davis
Title:	Chief Financial Officer

[Signature Page to Section 906 Certification]

Exhibit 15.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statements Nos. 333-205433, 333-205435, 333-205436 and 333-216253 on Form F-3 of our reports dated February 27, 2018, relating to the consolidated financial statements of Atlantica Yield plc and subsidiaries, and the effectiveness of Atlantica Yield plc and subsidiaries' internal control over financial reporting, appearing in this Annual Report on Form 20-F of Atlantica Yield plc for the year ended December 31, 2017.

/s/ Deloitte, S.L.

Madrid, Spain

March 7, 2018

Exhibit 15.2

INDEPENDENT AUDITORS' CONSENT

We consent to the incorporation by reference in Registration Statements No. 333-205433, 333-205435, 333-205436 and 333-216253 on Form F-3 of our report dated February 27, 2018, relating to the financial statements of Myah Bahr Honaine S.p.a. for the years ended December 31, 2017 and 2016 (which report expresses an unqualified opinion and includes an explanatory paragraph relating to the fact that the accompanying statements of income, comprehensive income, changes in equity and cash flows of Myah Bahr Honaine S.p.a. for the year ended December 31, 2015, were not audited, reviewed, or compiled by us and, accordingly, we do not express an opinion or any other form of assurance on them) appearing in the Annual Report on Form 20-F of Atlantica Yield plc for the year ended December 31, 2017.

/s/ Deloitte Algérie Sarl

Algiers, Algeria

March 7, 2018

Exhibit 99.1

INDEPENDENT AUDITORS' REPORT

To the Board of Directors and Shareholders of Atlantica Yield plc:

We have audited the accompanying financial statements of Myah Bahr Honaine S.p.a. (the "Company"), which comprise the statement of financial position as of December 31, 2017 and 2016, and the related statements of income, comprehensive income, changes in equity and cash flows for the years then ended, and the related notes to the financial statements.

Management's Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of these financial statements in accordance with International Financial Reporting Standards (IFRS) as issued by the International Accounting Standards Board; this includes the design, implementation, and maintenance of internal control relevant to the preparation and fair presentation of 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 financial statements based on our audit. We conducted our audit in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the Company's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control. Accordingly, we express no such opinion. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

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

Opinion

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of Myah Bahr Honaine S.p.a. as of December 31, 2017 and 2016, and the results of its operations and its cash flows for the years then ended in accordance with IFRS as issued by the International Accounting Standards Board.

Other Matter

The accompanying statements of income, comprehensive income, changes in equity and cash flows of Myah Bahr Honaine S.p.a. for the year ended December 31, 2015, were not audited, reviewed, or compiled by us and, accordingly, we do not express an opinion or any other form of assurance on them.

/s/ Deloitte Algérie Sarl

Algiers, Algeria

February 27, 2018

Audited financial statements of Myah Bahr Honaine S.p.a as of December 31, 2017 and for the year ended December 31, 2017 and 2016

Statement of financial position
Amounts in thousands of Usd

	Notes (1)	As of December 31, 2017	2016
Non-current assets			
Contracted concessional assets	5	185,273	196,161
Financial investments	6	361	382
Total non-current assets		**185,634**	**196,543**
Current assets			
Trade and other receivables	6&7	8,936	9,369
Prepayments	6	27	308
Financial investments	5&6	32,531	25,359
Cash and cash equivalents	6&8	28,785	29,214
Total current assets		**70,279**	**64,250**
Total assets		**255,913**	**260,793**
Equity and liabilities			
Share capital	9	45,989	45,989
Legal reserve	9	4,457	4,457
Retained earnings		112,562	99,853
Profit/(loss) for the year		29,158	24,967
Currency translation differences		(40,739)	(33,933)
Total equity		**151,427**	**141,333**
Non-current liabilities			
Long-term project debt		89,387	102,861
Provisions		936	979
Total non-current liabilities	6&10	**90,323**	**103,840**
Current liabilities			
Related parties	6&13	2,300	4,302
Short-term project debt	6&10	11,047	11,207
Trade and other payables	6&10	816	110
Total current liabilities		**14,163**	**15,620**
Total equity and liabilities		**255.913**	**260,793**

(1) Notes 1 to 14 are an integral part of the financial statements

Income Statement
Amounts in thousands of Usd

	Notes (1)	For the year ended December 31, 2017	2016	2015 (unaudited)
Revenue	12	51,459	47,828	54,409
Other operating income		7	12	2,462
Employee benefit expenses		(356)	(453)	(430)
Depreciation, amortization and impairment charges		(22)	(21)	(16)
Other operating expenses	12	(17,926)	(17,898)	(17,601)
Operating profit		**33,162**	**29,468**	**38,823**
Financial income	12	133	37	251
Financial expenses	12	(4,137)	(4,538)	(5,545)
Financial expenses, net		**(4,004)**	**(4,501)**	**(5,294)**
Profit before income tax		**29,158**	**24,967**	**33,530**
Income tax		-	-	-
Profit for the year		**29,158**	**24,967**	**33,530**

(1) Notes 1 to 14 are an integral part of the financial statements

Statements of comprehensive income
Amounts in thousands of Usd

	For the year ended December 31,		
	2017	2016	2015 (unaudited)
Profit for the year	**29,158**	**24,967**	**33,530**
Items that may be subject to transfer to income statement			
Currency translation differences	(6,806)	(3,587)	(30,346)
Total comprehensive income for the year	**22,352**	**21,380**	**3,184**

Statements of changes in equity
Amounts in thousands of Usd

	Notes (1)	Share capital	Retained earnings	Legal reserve	Profit for the year	Currency translation differences	Total Equity
Balance at January 1, 2015		**45,989**	**111,801**	**2,165**	**-**	**-**	**159,955**
Dividend distribution		-	(21,864)	-	-	-	**(21,864)**
Allocation to legal reserves			(1,319)	1,319	-	-	-
Profit for the year		-	-	-	33,530	-	**33,530**
Currency translation differences		-		-	-	(30,346)	**(30,346)**
Balance at December 31, 2015		**45,989**	**88,618**	**3,484**	**33,530**	**(30,346)**	**141,275**
Distribution of prior year results		-	32,557	973	(33,530)	-	-
Dividend distribution			(21,322)	-	-	-	**(21,322)**
Profit for the year		-	-	-	24,967	-	**24,967**
Currency translation differences		-	-	-	-	(3,587)	**(3,587)**
Balance at December 31, 2016		**45,989**	**99,853**	**4,457**	**24,967**	**(33,933)**	**141,333**
Distribution of prior year result		-	24,967	-	(24,967)	-	-
Dividend distribution		-	(12,258)	-	-	-	**(12,258)**
Profit for the year		-	-	-	29,158		**29,158**
Currency translation differences		-	-	-	-	(6,806)	**(6,806)**
Balance at December 31, 2017		**45,989**	**112,562**	**4,457**	**29,158**	**(40,739)**	**151,427**

(1) Notes 1 to 14 are an integral part of the financial statements

Statements of cash flow
Amounts in thousands of Usd

	Notes (1)	For the year ended December 31, 2017	2016	2015 (unaudited)
I. Profit for the year		**29,158**	**24,967**	**33,530**
Non-monetary adjustments				
Depreciation, amortization and impairment charges		22	21	16
Finance (income)/expenses		4,004	4,501	5,294
Other non-monetary items		(6,238)	3,336	(1,677)
II. Profit for the year adjusted by non-monetary items		**26,946**	**32,825**	**37,163**
III. Variations in working capital		**(2,114)**	**(3,391)**	**1,334**
Net interest paid		(4,014)	(4,535)	(5,313)
A. Net cash provided by operating activities		**20,818**	**24,899**	**33,184**
Investment in contracted concessional assets		(21)	(67)	(35)
B. Net cash used in investing activities		**(21)**	**(67)**	**(35)**
Repayment of Project debt		(8,878)	(8,659)	(9,120)
Dividends paid to company´s shareholders		(12,258)	(21,322)	(21,864)
C. Net cash used in financing activities		**(21,136)**	**(29,982)**	**(30,985)**
Net increase/(decrease) in cash and cash equivalents		**(339)**	**(5,150)**	**2,165**
Cash and cash equivalents at beginning of the year		29,214	34,367	32,431
Translation differences on cash and cash equivalents		(90)	(4)	(228)
Cash and cash equivalents at end of the year		**28,785**	**29,214**	**34,367**

(1) Notes 1 to 14 are an integral part of the financial statements

Note 1.- Nature of the business

Myah Bahr Honaine S.p.a. ("MBH" or "the Company"), was incorporated in Algeria as a Société par actions on September 16, 2006.

The main activity of the Company is the operation of a water desalination plant located in Taffsout, Algeria, near three important cities: Oran, to the northeast, and Sidi Bel Abbés and Tlemcen, to the southeast. The offices are located in Dely Ibrahim, Alger (Algeria).

The technology selected for the Honaine plant is currently the most commonly used in this kind of project. It consists in desalination using membranes by reverse osmosis. MBH has a capacity of seven million of cubic feet (M ft3) per day of desalinated water and has been in operation since July 2012. The project serves a population of approximately 1 million.

The water purchase agreement is a U.S. dollar indexed 25-year take-or-pay contract with Sonatrach/Algerienne des Eaux ("ADE"), from Commercial Operation Date ("COD") in July 2012. The tariff structure is based upon plant capacity and water production, covering variable cost (water cost plus electricity cost). Tariffs are adjusted monthly based on the indexation mechanisms that include local inflation, U.S. inflation and the exchange rate between the U.S. dollar and local currency.

The following table provides an overview of the concessional asset:

Asset	Type	Location	Capacity (Gross)	Counterparty Credit Ratings	COD(1)	Contract Years Left(2)
Honaine	Water	Algeria	7 M ft3/ day	Not rated	3Q 2012	20

(1) Commercial Operation Date ("COD").
(2) As of December 31, 2017.

On February 3, 2015, Atlantica Yield Plc ("Atlantica") completed the acquisition of 25.5% of MBH held by Abengoa. The Company is currently 49% owned by Algerian Energy Company, SPA ("AEC")[1] and 51% by Geida Tlemcen, S.L. At the same time, Geida Tlemcen S.L. is 50% owned by Valoriza Agua, S.L., a subsidiary of Sacyr, S.A., and 50% by ABY Concessions Infrastructures, S.LU., a subsidiary of Atlantica (see Note 9).

Atlantica is a public limited company listed on the NASDAQ Global Select Market and incorporated in England and Wales. It is a total return company that owns, manages, and acquires renewable energy, efficient natural gas power, electric transmission lines and water revenue-generating assets, focused on North America (United States and Mexico), South America (Peru, Chile and Uruguay) and Europe and Middle East (EMEA).

These financial statements of MBH as of and for the year ended December 2017, have been prepared in connection with Rule 3-09 of Regulation S-X, of the US Securities and Exchange Commission (SEC) which requires to file with the SEC, the separate financial statements of a significant equity method investee.

These financial statements were approved and authorized for issuance by Francisco Martinez Davis, Chief Executive Officer of Atlantica, on February 27, 2018.

[1] AEC is the Algerian agency in charge of delivering Algeria's large-scale desalination program. It is a joint venture set up in 2001 between the national oil and gas company, Sonatrach, and the national gas and electricity company, Sonelgaz. Each of Sonatrach and Sonelgaz owns 50% of AEC.

Note 2.- Basis of preparation

2.1. Statement of compliance

These financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS") adopted by the International Accounting Standard (IAS) Board (hereinafter, IFRS-IASB) and show the equity and financial situation at December 31, 2017 and 2016, as well as the gains and losses on its operations, changes in its equity and cash flow statement for the reporting period ended as of December 31, 2017, 2016 and 2015.

These financial statements have been prepared under the going-concern assumption.

The Company does not have any subsidiary as of and for any period presented and the financial information presented herein only reflects the transactions related to MBH.

2.2. Application of new accounting standards

a) Standards, interpretations and amendments effective from January 1, 2017 under IFRS-IASB, applied by the Company in the preparation of these consolidated financial statements:

- IAS 7 (Amendment) 'Disclosure Initiative'. Requirements for additional disclosures in order to provide users with improved financial information.

- IAS 12 (Amendment) 'Recognition for Deferred Tax for Unrealized Losses'. Clarification of recognition of deferred tax assets for unrealized losses.

- Annual Improvements to IFRSs 2014-2016 cycles. Amendments to IFRS 12.

The applications of these amendments have not had any material impact on these consolidated financial statements except for the reconciliation of liabilities arising from financial activities that has been included in Note 14 and 15.

b) Standards, interpretations and amendments published by the IASB that will be effective for periods beginning on or after January 1, 2018:

- IFRS 9 'Financial Instruments'. This Standard is applicable for annual periods beginning on or after January 1, 2018 under IFRS-IASB, earlier application is permitted.

- IFRS 9 (Amendments to IFRS 9): Prepayment Features with Negative Compensation. This Standard is applicable for annual periods beginning on or after January 1, 2019 under IFRS-IASB, earlier application is permitted.

- IFRS 15 'Revenues from Contracts with Customers'. This Standard is applicable for annual periods beginning on or after January 1, 2018 under IFRS-IASB, earlier application is permitted.

- IFRS 15 (Clarifications) 'Revenues from Contracts with Customers'. This amendment is mandatory for annual periods beginning on or after January 1, 2018 under IFRS-IASB, earlier application is permitted.

- IFRS 16 'Leases'. This Standard is applicable for annual periods beginning on or after January 1, 2019 under IFRS-IASB, earlier application is permitted.

- IFRS 17 'Insurance Contracts'. This Standard is applicable for annual periods beginning on or after January 1, 2021 under IFRS-IASB, earlier application is permitted.

- IFRS 2 (Amendment) 'Classification and Measurement of Share-based Payment Transactions'. This amendment is mandatory for annual periods beginning on or after January 1, 2018 under IFRS-IASB, earlier application is permitted.

- IFRS 4 (Amendment). Applying IFRS 9 ‘Financial Instruments’ with IFRS 4 ‘Insurance Contracts’. This amendment is mandatory for annual periods beginning on or after January 1, 2018 under IFRS-IASB, earlier application is permitted.

- IAS 40 (Amendment). Transfers of Investment Property. This amendment is mandatory for annual periods beginning on or after January 1, 2018 under IFRS-IASB, earlier application is permitted.

- IAS 19 (Amendment). Amendments to IAS 19: Plan Amendment, Curtailment or Settlement. This amendment is mandatory for annual periods beginning on or after January 1, 2019 under IFRS-IASB, earlier application is permitted.

- IAS 28 (Amendment). Long-term Interests in Associates and Joint Ventures. This amendment is mandatory for annual periods beginning on or after January 1, 2018 under IFRS-IASB, earlier application is permitted.

- Annual Improvements to IFRSs 2014-2016 cycles. Other minor amendments and modifications different from the aforementioned on IFRS 12. This Standard is applicable for annual periods beginning on or after January 1, 2018 under IFRS-IASB.

- Annual Improvements to IFRSs 2015-2017 cycles. This Standard is applicable for annual periods beginning on or after January 1, 2018 under IFRS-IASB.

- IFRIC 22 Foreign Currency Transactions and Advance Consideration. This Standard is applicable for annual periods beginning on or after January 1, 2018 under IFRS-IASB.

- IFRIC 23 Uncertainty over Income Tax Treatments. This Standard is applicable for annual periods beginning on or after January 1, 2019 under IFRS-IASB.

- IFRS 10 and IAS 28. Parent disposes of (or contributes) its controlling interest in a subsidiary to an existing associate or joint venture. Effective date beginning on or after a date to be determined by the IASB.

The Company does not anticipate the effect of the application of any of the above standards, interpretations or amendments to have a significant effect in the financial statements of the Company.

2.3. Critical accounting policies and estimates

Some of the accounting policies applied require the application of significant judgment by management to select the appropriate assumptions to determine these estimates. These assumptions and estimates are based on historical experience, advice from experienced consultants, forecasts and other circumstances and expectations as of the close of the financial period. The assessment is considered in relation to the global economic situation of the industry and region where the Company operates, taking into account future development of the businesses. By their nature, these judgments are subject to an inherent degree of uncertainty; therefore, actual results could materially differ from the estimates and assumptions used. In such cases, the carrying values of assets and liabilities are adjusted.

The most critical accounting policies, which reflect significant management estimates and judgment to determine amounts in these financial statements, are Contracted concessional agreements (see Note 3.1.).

As of the date of preparation of these financial statements, no relevant changes in the estimates made are anticipated and, therefore, no significant changes in the value of the assets and liabilities recognized at December 31, 2017, are expected.

Although these estimates and assumptions are being made using all available facts and circumstances, it is possible that future events may require management to amend such estimates and assumptions in future periods. Changes in accounting estimates are recognized prospectively, in accordance with IAS 8, in the income statement of the year in which the change occurs.

2.4.1. Useful lives of contracted concessional assets items

The useful lives of contracted concessional assets are estimated in accordance with the foreseeable life cycles for the use of desalination plants. The Company reviews the useful lives of the plant every year. In the case of technical innovations and changes in the cycles of the sector in which it operates, the Company determine whether it is necessary to correct that estimate, and if the estimate differs from that previously performed, the effect of the change is accounted on a prospective basis beginning from the year in which the change is made.

2.4.2. Revenue recognition

As mentioned in Note 1, MBH signed a "public-to-private" arrangement to build, operate and transfer of a concessional infrastructure for a 25 year period which includes the design of the infrastructure, as well as the services related to its operation and maintenance for the period agreed.

Consequently, as per the provisions of International Financial Reporting Interpretations Committee 12 ("IFRIC 12"), the Company recognized a financial asset at the fair value of the construction services and measured revenue and costs for providing construction services during the period of construction of the infrastructure in accordance with IAS 11 "Construction Contracts".

Project name	**Country**	**Period of Concession**	**Offtaker**	**Arrangement Terms (price)**	**Description of the Arrangement**
Honaine	Algeria	25 Years	Sonatrach & ADE	U.S. dollar indexed take-or-pay contract with Sonatrach / ADE	25 years purchase agreement

The financial asset is subsequently recorded at amortized cost calculated according to the effective interest method. Revenue from operations and maintenance services is recognized in each period according to IAS 18 "Revenue". The remuneration of managing and operating the asset resulting from the valuation at amortized cost is also recorded in revenue.

2.4. Functional currency and presentation currency

The financial statements are presented in thousands of US Dollars (Usd). The functional currency of the Company is the Dinar (DZD).

The conversion to the presentation currency from the functional currency has been performed using the following procedures:

- Assets and liabilities for each statement of financial position presented were translated at the closing rate;
- For each period presented, income and expenses in the period were translated at the average exchange rate of the period;
- All resulting exchange differences were recognized in the other comprehensive income.

The conversion to the presentation currency has a negative impact in equity, due to the appreciation of the USD against the DZD, within the line Other comprehensive income, of Usd 40,739 thousand and Usd 33,933 thousand as of December 31, 2017 and 2016, respectively.

Note 3.- Significant accounting policies

These are the principal accounting policies used in preparing these financial statements:

3.1. Contracted Concessional Assets

Contracted concessional assets include fixed assets financed through project debt, related to service concession arrangements recorded in accordance with IFRIC 12.

The application of IFRIC 12 requires extensive judgment in relation with, among other factors, (i) the identification of certain infrastructures and contractual agreements in the scope of IFRIC 12, (ii) the understanding of the nature of the payments in order to determine the classification of the infrastructure as a financial asset or as an intangible asset and (iii) the timing and recognition of the revenue from construction and concessionary activity.

The Company recognizes a financial asset as the demand risk is assumed by the grantor, to the extent that the concession holder has an unconditional right to receive payments for the asset and the only substantial risk of non-recovery of the initial investment is credit deterioration of the counterparty.

This asset was initially recognized at the fair value of the construction services provided, in accordance with IAS 11. The financial asset is subsequently recorded at amortized cost calculated according to the effective interest method. Revenue from operations and maintenance services is recognized in each period according to IAS 18 “Revenue”. The remuneration of managing and operating the asset resulting from the valuation at amortized cost is also recorded in revenue.

3.2. Financial investments

Financial investments are initially measured at fair value. Transaction costs that are directly attributable to the acquisition of financial assets are added to the fair value of the financial assets on initial recognition.

The classification of financial investments depends on the nature and purpose for which they were acquired. Management determines the classification of its financial assets at initial recognition.

Financial investments held by the Company other than Contracted Concessional Assets are classified as ‘Trade and other receivables'.

Trade and other receivables are non-derivative financial assets with fixed or determinable payments, not listed on an active market. After initial recognition, they are measured at amortized cost in accordance with the effective interest rate method.

The effective interest method is a method of calculating the amortised cost of a debt instrument and of allocating interest income over the relevant period. The effective interest rate is the rate that exactly discounts estimated future cash receipts (including all fees and points paid or received that form an integral part of the effective interest rate, transaction costs and other premiums or discounts) through the expected life of the debt instrument, or, where appropriate, a shorter period, to the net carrying amount on initial recognition.

Trade and other receivables are assessed for indicators of impairment at the end of each reporting period. Trade receivables are assessed for impairment on a collective basis even if they were assessed not to be impaired individually. Objective evidence of impairment for a portfolio of receivables could include the Company's past experience of collecting payments, an increase in the number of delayed payments, as well as observable changes in national or local economic conditions that correlate with default on receivables.

Pursuant to IAS 39, an impairment loss is recognized if the carrying amount of these assets exceeds the present value of future cash flows discounted at the initial effective interest rate.

3.3. Financial liabilities

Financial liabilities include project debt and trade and other payables, which are further described in Note 10.

Borrowings and trade and other payables are initially measured at fair value, net of transaction costs incurred. They are subsequently measured at amortized cost using the effective interest rate method. Any difference between the proceeds initially received (net of transaction costs incurred in obtaining such proceeds) and the repayment value is recognized in the income statement over the duration of the borrowing using the effective interest rate method.

3.4. Related party transactions

In general, operations with related parties are initially recorded at their fair value. The subsequent valuation is made in accordance with the terms set out in the corresponding regulations (refer to Note 13).

3.5. Cash and cash equivalents

Cash and cash equivalents include cash in hand, cash in bank and other highly-liquid current investments with an original maturity of three months or less which are held for the purpose of meeting short-term cash commitments.

3.6. Classification of assets and liabilities as current or non-current.

The Company presents the Statement of financial position classifying assets and liabilities between current and non-current. For these purposes, assets and liabilities are considered current if they meet the following criteria:

- Assets are classified as current if it is expected that they will be realized, sold or consumed within twelve months from the date of close;

- Liabilities are classified as current if it is expected that they will be settled within twelve months from the date of close, or the Company does not have the unconditional right to defer the cancellation of the liabilities during the twelve months following the date of close.

Note 4.- Financial risk management

Financial risk factors

The activities carried out by the Company are exposed to different financial risks: market risk, credit risk and liquidity risk.

Management of the Company seeks to minimize the potential adverse effects of these risks on the Company's financial profitability.

Market risk

The Company is not exposed to interest rate risk considering its debt is at a fixed interest rate. Tariffs of the water purchase agreement are adjusted monthly based on the indexation mechanisms that include local inflation, U.S. inflation and the exchange rate between the U.S. dollar and the local currency.

Credit risk

The Company considers that it has limited credit risk with clients as revenues are derived from revenue contracted agreement with state-owned entities.

Liquidity risk

The aim of the Company's liquidity and financing policy is to ensure that the Company has sufficient availability of funds to meet its financial commitments.

The Company aims to have adequate capacity for the repayment of its debt in relation to its cash generation capacity.

The Company has a project financing in place. The repayment profile of this debt is established on the basis of the projected cash flow generation of the business. This ensures that sufficient financing is available to meet deadlines and maturities, which mitigates the liquidity risk significantly.

Note 5.- Contracted concessional assets

The amounts and variations registered during the 2017 and 2016 financial year for Contracted concessional assets were:

	Balance as of December 2016	Additions	Disposals/Other movement	Currency translation differences	Balance as of December 2017
Property plant and equipment - gross	197	23	(52)	(9)	159
Accumulated depreciation	(127)	(22)	52	5	(92)
Property plan equipment, net	**70**	**1**	**-**	**(4)**	**67**
Financial assets	**196,091**	**-**	**(2,349)**	**(8,536)**	**184,206**
Total contracted concessional assets	**196,161**	**1**	**(2,349)**	**(8,540)**	**185,273**

	Balance as of December 2015 (unaudited)	Additions	Disposals/Other movement	Currency translation differences	Balance as of December 2016
Property plant and equipment - gross	205	7	(9)	(5)	197
Accumulated depreciation	(136)	(4)	9	3	(127)
Property plan equipment, net	**69**	**3**	**-**	**(2)**	**70**
Financial assets	**196,097**	**4,973**	**-**	**(4,979)**	**196,091**
Total contracted concessional assets	**196,166**	**4,975**	**-**	**(4,980)**	**196,161**

Contracted concessional assets include mainly the water plant financed through project debt which is accounted for as a financial liability (see Note 10), and relating to service concession arrangements, which is accounted for as a financial asset in accordance with IFRIC 12. The current portion of this financial asset amounts to Usd 32.5 million and Usd 25.4 million as of December 31, 2017 and 2016 respectively (Note 6.1.).

Property plan and equipment primarily include surface rights, furniture, information processing and transportation equipments.

No losses from impairment of “Contracted concessional assets” were recorded during 2017 and 2016.

Note 6.- Breakdown of financial instruments

6.1. The breakdown of the financial assets as of December 31, 2017 and 2016 is as follows:

	Balance as of December 31,	
	2017	**2016**
Clients (Note 7)	8,739	9,271
Prepayments	27	308
VAT receivable (Note 11)	197	99
Financial investments	32,892	25,741
Of which, non-current portion	361	382
Of which, current portion	32,531	25,359
Cash and cash equivalents (Note 8)	28,785	29,214
Total	**70,640**	**64,633**

As of December 31, 2017, and 2016, financial investments include the current portion of contracted concessional assets (Note 5).

6.2. The breakdown of long-term financial liabilities as of December 31, 2017 and 2016 is as follows:

	Balance as of December 31,	
	2017	**2016**
Long-term project debt (Note 10)	89,387	102,861
Provisions (Note 10)	936	979
Total	**90,323**	**103,840**

The breakdown of short-term financial liabilities as of December 31, 2017 and 2016 is as follows:

	Balance as of December 31,	
	2017	**2016**
Related parties (Note 13)	2,300	4,302
Short-term project debt (Note 10)	11,047	11,207
Trade accounts payable and other (Note 10)	816	110
Total	**14,163**	**15,620**

6.3. Analysis by maturities

Amounts of financial instruments with a maturity which is defined or which may be defined classified by year of maturity are as follows:

As of December 31, 2017:

Financial assets	**2018**	**Subsequent years**	**Total**
Clients	8,739	-	8,739
Prepayments	27	-	27
VAT receivable	197	-	197
Financial investments	32,531	361	32,892
Total	**41,494**	**361**	**41,855**

Financial liabilities	2018	2019	Subsequent years	Total
Debt with related parties	2,300	-	-	2,300
Project debt	11,047	9,240	80,147	100,434
Trade accounts payable and other	816	-	-	816
Provisions	-	-	936	936
Total	**14,163**	**9,240**	**81,083**	**104,486**

As of December 31, 2016:

Financial assets	2017	Subsequent years	Total
Clients	9,271	-	9,271
Prepayments	308	-	308
VAT receivable	99	-	99
Financial investments	25,359	382	25,741
Total	**35,037**	**382**	**35,419**

Financial liabilities	2017	2018	Subsequent years	Total
Debt with related parties	4,302	-	-	4,302
Project debt	11,207	9,305	93,556	114,068
Trade accounts payable and other	110	-	-	110
Provisions	-	-	979	979
Total	**15,620**	**9,305**	**94,535**	**119,460**

Note 7.- Trade and other receivables

The details of trade and other receivables as of December 31, 2017 and 2016 is as follows:

	Balance as of December 31,	
	2017	**2016**
Clients	8,739	9,271
VAT receivable	197	99
Total	**8,936**	**9,369**

The balance indicated in clients fully refers to collection rights with ADE and risk of its balances is minimal, as the collection period is lower than three months.

There were no provisions for impairment losses of loans and accounts receivable at December 31, 2017 and 2016.

Note 8.- Cash and cash equivalents

Cash and cash equivalents corresponds entirely to cash on hand as of December 31, 2017 and 2016.
Cash at hand represent liquid resources held in bank accounts.

Note 9.- Capital and reserves

As of December 31, 2017 and 2016 the share capital is DZD 4,015,000 thousand comprising 401,500 ordinary shares of one single class and series, all vested with identical economic and voting rights, of a face value of DZD 10,000 each, fully subscribed and paid.

The percentage of ownership of the shareholders of the Company is as follows:

	% of shares
Algerian Energy Company, SPA	49%
Geida Tlemcen, S.L.	51%
Total	**100%**

Legal reserve

In accordance with Article 721 of the Algerian *Code de Commerce*, a figure equal to 5% of the profit of the financial year must be used to create a legal reserve until it reaches the level of at least 10% of the share capital. This reserve may not be distributed. As of December 31, 2017, the legal reserve represents a 10% of the share capital.

On April 11, 2016, the shareholders of the Company approved during the ordinary shareholder´s meeting to declare a dividend of DZD 2,334,321,000, accounting for a dividend per share of DZD 5,814.

On April 19, 2017, the shareholders of the Company approved during the ordinary shareholder´s meeting to declare a dividend of DZD 1,359,479,000, accounting for a dividend per share of DZD 3,386.

Note 10.- Project debt and other payables

The breakdown of project debt and other payables as of December 31, 2017 and 2016 are as follows:

	Balance as of December 31,	
	2017	**2016**
Long-term debt and payable		
Provisions	936	979
Project debt	89,387	102,861
Total long-term debt and payable	**90,323**	**103,840**
Short-term debt and Other payables		
Project debt	11,047	11,207
Payables to related parties	2,300	4,302
Trade accounts payable and other	816	110
Total short-term debt and payable	**14,163**	**15,620**
Total debt and other payables	**104,486**	**119,460**

Long and short-term project debt corresponds to the facility agreement, signed in May 2007 and amended in November 2008 and June 2013 with Crédit Populaire d'Algerie, or CPA. The final amount of the loan drawn down was DZD 16,042 million and it accrues a fixed-rate interest of 3.75%. The repayment schedule of this debt is made up of sixty quarterly payments, ending in April 2027.

The carrying value of other liabilities such as trade payables approximates the fair value, given the nature and maturity of these liabilities.

Note 11.- Tax position

The company is registered to the ANDI "Agence Nationale de Developpement de L`investissement". This registration grants advantage for companies who invest in Algeria and register to this agency with some conditions. The Company gets from this agency the following benefits:

- Exemptions from the income tax ("IBS");
- Exemption from tax on professional activity ("TAP").

These benefits are for 10 years from the beginning of the project, being December 11, 2011. After that period, in case the exemption is not extended, a claim may be made under the water purchase agreement for compensation in the tariff.

Due to this income tax exemption, the Company has not registered any income tax asset or liability.

The detail of the current tax receivables and payables as of December 31, 2017 and 2016 is as follows:

	Balance as of December 31,	
	2017	**2016**
VAT refundable	197	99
Total	**197**	**99**

As of December 31, 2017 and 2016, the Company has an open tax inspection with the tax authorities related to the years 2016, 2015, 2014 and 2013.

Note 12.- Revenue and Expenses

12.1. Revenue for the years ended December 31, 2017 and 2016 amount to Usd 51,459 thousand and Usd 47,828 thousand respectively, and fully relate to the water purchase agreement.

12.2. Breakdown of Other operating expenses for the years ended December 31, 2017 and 2016 are as follows:

	For the year ended December 31,		
Other operating expenses	**2017**	**2016**	**2015 (unaudited)**
Operation and maintenance	(10,652)	(10,862)	(11,125)
Leases	(183)	(194)	(199)
External technical services	(253)	(102)	(198)
Insurance premiums	(613)	(638)	(665)
Customs duties	(245)	(101)	(136)
Supplies	(5,677)	(5,632)	(4,915)
Other expenses	(303)	(369)	(364)
Total other operating expenses	**(17,926)**	**(17,898)**	**(17,601)**
Related parties (Note 13)	(10,652)	(10,862)	(11,125)
Other than related parties	(7,274)	(7,037)	(6,477)

Other operating expenses mainly relates to operation and maintenance for which MBH signed an operation and maintenance contract and a membrane and chemical products supply contract with UTE Honaine O&M (a joint venture between Abengoa Water, S.L. and Sacyr, S.A., each holding 50%). This transaction with Abengoa Water S.L. is considered a related party transaction (see Note 13).

The O&M agreement is a 25-year contract from COD and is composed of a fixed fee and a variable component. The fixed O&M cost covers mainly structural and staff costs. The variable O&M cost covers the chemical products, filters cost and membranes costs related to the water production.

12.3. Breakdown of financial result for the years ended December 31, 2017 and 2016 is as follows:

Financial result	For the year ended December 31, 2017	2016	2015 (unaudited)
Financial income	133	37	251
Interest related to project debt	(4,137)	(4,538)	(5,545)
Total financial result	**(4,004)**	**(4,501)**	**(5,294)**
Other than related parties	(4,004)	(4,501)	(5,294)

The decrease of the financial result is mainly due to the effect of the repayment schedule of the project debt, which has decreased by $8.9 million during the year 2016 (see Note 10).

Note 13.- Related Parties

The breakdown of balances and transactions with related parties as of December 31, 2017 and 2016 is as follows:

As of December 31, 2017:

Company		Short term payables
Geida Tlemcen, S.L.	Shareholder	1
Valoriza Aguas, S.L.	O&M	1,436
Abengoa Water, S.L.	O&M	425
Algerian Energy Company SPA	Shareholder	-
Sonelgaz SPA	Affiliate	438
Total		**2,300**

Company		Operating expenses
Valoriza Aguas, S.L.	O&M	(4,847)
Abengoa Water, S.L.	O&M	(5,805)
Total		**(10,652)**

As of December 31, 2016:

Company		Short term payables
Geida Tlemcen, S.L.	Shareholder	1
Valoriza Aguas, S.L.	O&M	2,827
Abengoa Water, S.L.	O&M	864
Algerian Energy Company SPA	Shareholder	152
Sonelgaz SPA	Affiliate	459
Total		**4,302**

Company		Operating expenses
Valoriza Aguas, S.L.	O&M	(6,447)
Abengoa Water, S.L.	O&M	(4,414)
Total		**(10,862)**

Note 14.- Subsequent Events

No material event occurred after the balance sheet date ending December 31, 2017.