ORMAT TECHNOLOGIES, INC.
Form 10-K
February 26, 2016

UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-K

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

For the fiscal year ended December 31, 2015
Or
TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

Commission file number: 001-32347

ORMAT TECHNOLOGIES, INC.

(Exact name of registrant as specified in its charter)

DELAWARE	**88-0326081**
(State or other jurisdiction of incorporation or organization)	*(I.R.S. Employer Identification Number)*

6225 Neil Road, Reno, Nevada 89511-1136

(Address of principal executive offices, including zip code)

Registrant's telephone number, including area code:

(775) 356-9029

(Registrant's telephone number, including area code)

Securities Registered Pursuant to Section 12(b) of the Act:

Title of Each Class	Name of Each Exchange on Which Registered
Common Stock $0.001 Par Value	New York Stock Exchange

Securities Registered Pursuant to Section 12(g) of the Act:

None

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

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Exchange Act. 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 if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K.

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer Accelerated filer Non-accelerated filer Smaller reporting company

(Do not check if a smaller reporting company)

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes No

As of June 30, 2015, the last business day of the registrant's most recently completed second fiscal quarter, the aggregate market value of the registrant's common stock held by non-affiliates of the registrant was $1,418,095,165 based on the closing price as reported on the New York Stock Exchange. As described herein, the aggregate market value of common stock held by non-affiliates of the registrant increased significantly on February 12, 2015, which is the date on which the share exchange contemplated by the Share Exchange Agreement (as described herein) was completed.

Indicate the number of shares outstanding of each of the registrant's classes of common stock as of the latest practicable date: As of February 23, 2016, the number of outstanding shares of common stock, par value $0.001 per share was 49,112,901.

Documents incorporated by reference: Part III (Items 10, 11, 12, 13 and 14) incorporates by reference portions of the Registrant's Proxy Statement for its Annual Meeting of Stockholders, which will be filed not later than 120 days after December 31, 2015.

ORMAT TECHNOLOGIES, INC.

FORM 10-K FOR THE YEAR ENDED DECEMBER 31, 2015

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Glossary of Terms

When the following terms and abbreviations appear in the text of this report, they have the meanings indicated below:

Term	Definition
AER	Alternative Earth Resources Inc.
Amatitlan Loan	$42,000,000 in initial aggregate principal amount borrowed by our subsidiary Ortitlan Limitada from Banco Industrial S.A. and Westrust Bank (International) Limited.
AMM	Administrador del Mercado Mayorista (administrator of the wholesale market — Guatemala)
ARRA	American Recovery and Reinvestment Act of 2009
Auxiliary Power	The power needed to operate a geothermal power plant’s auxiliary equipment such as pumps and cooling towers
Availability	The ratio of the time a power plant is ready to be in service, or is in service, to the total time interval under consideration, expressed as a percentage, independent of fuel supply (heat or geothermal) or transmission accessibility
Balance of Plant equipment	Power plant equipment other than the generating units including items such as transformers, valves, interconnection equipment, cooling towers for water cooled power plants, etc.
BLM	Bureau of Land Management of the U.S. Department of the Interior
BOT	Build, operate and transfer
Capacity	The maximum load that a power plant can carry under existing conditions, less auxiliary power
Capacity Factor	The ratio of the average load on a generating resource to its generating capacity during a specified period of time, expressed as a percentage
CARB	California Air Resources Board
CGC	Crump Geothermal Company LLC
C&I	Refers to the Commercial and Industrial sectors, excluding residential
CNE	National Energy Commission of Honduras
CNEE	National Electric Energy Commission of Guatemala
COD	Commercial Operation Date
Company	Ormat Technologies, Inc., a Delaware corporation, and its consolidated subsidiaries
COSO	Committee of Sponsoring Organizations of the Treadway Commission
CPI	Consumer Price Index
CPUC	California Public Utilities Commission
DEG	Deutsche Investitions-und Entwicklungsgesellschaft mbH
DFIs	Development Finance Institutions
DOE	U.S. Department of Energy
DOGGR	California Division of Oil, Gas, and Geothermal Resources
DSCR	Debt Service Coverage Ratio
EBITDA	Earnings before interest, taxes, depreciation and amortization
EGS	Enhanced Geothermal Systems
ENEE	Empresa Nacional de Energía Eléctrica
Enthalpy	The total energy content of a fluid; the heat plus the mechanical energy content of a fluid (such as a geothermal brine), which, for example, can be

partially converted to mechanical energy in an Organic Rankine Cycle.

Term	**Definition**
EPA	U.S. Environmental Protection Agency
EPC	Engineering, procurement and construction
EPS	Earnings per share
ERC	Kenyan Energy Regulatory Commission
ESC	Energy Sales Contract
Exchange Act	U.S. Securities Exchange Act of 1934, as amended
FASB	Financial Accounting Standards Board
FERC	U.S. Federal Energy Regulatory Commission
FPA	U.S. Federal Power Act, as amended
GAAP	Generally accepted accounting principles
GCCU	Geothermal Combined Cycle Unit
GDC	Geothermal Development Company
GEA	Geothermal Energy Association
Geothermal Power Plant	The power generation facility and the geothermal field
Geothermal Steam Act	U.S. Geothermal Steam Act of 1970, as amended
GHG	Greenhouse gas
GNP	Gross National Product
HELCO	Hawaii Electric Light Company
IFC	International Finance Corporation
IID	Imperial Irrigation District
ILA	Israel Land Administration
INDE	Instituto Nacional de Electrification
IPPs	Independent Power Producers
ISO	International Organization for Standardization
ITC	Investment tax credit
ITC Cash Grant	Payment for Specified Renewable Energy property in lieu of Tax Credits under Section 1603 of the ARRA
John Hancock	John Hancock Life Insurance Company (U.S.A.)
JPM	JPM Capital Corporation
KenGen	Kenya Electricity Generating Company Ltd.
Kenyan Energy Act	Kenyan Energy Act, 2006
KETRACO	Kenya Electricity Transmission Company Limited
KLP	Kapoho Land Partnership
KPLC	Kenya Power and Lighting Co. Ltd.
kVa	Kilovolt-ampere
kW	Kilowatt - A unit of electrical power that is equal to 1,000 watts
kWh	Kilowatt hour(s), a measure of power produced
Mammoth Pacific	Mammoth-Pacific, L.P.
MACRS	Modified Accelerated Cost Recovery System
MIGA	Multilateral Investment Guarantee Agency, a member of the World Bank Group
MW	Megawatt - One MW is equal to 1,000 kW or one million watts
MWh	Megawatt hour(s), a measure of energy produced

Term	**Definition**
NBPL	Northern Border Pipe Line Company
NIS	New Israeli Shekel
NGI	Natural Gas-California SoCal-NGI Natural Gas price index
NV Energy	NV Energy, Inc.
NYSE	New York Stock Exchange
OEC	Ormat Energy Converter
OFC	Ormat Funding Corp., a wholly owned subsidiary of the Company
OFC Senior Secured Notes	$190,000,000 8.25% Senior Secured Notes, due 2020 issued by OFC
OFC 2	OFC 2 LLC, a wholly owned subsidiary of the Company
OFC 2 Senior Secured Notes	Up to $350,000,000 Senior Secured Notes, due 2034 issued by OFC 2
OMPC	Ormat Momotombo Power Company, a wholly owned subsidiary of the Company
OPC	OPC LLC, a consolidated subsidiary of the Company
OPC Transaction	Financing transaction involving four of our Nevada power plants in which institutional equity investors purchased an interest in our special purpose subsidiary that owns such plants.
OPIC	Overseas Private Investment Corporation
OrCal	OrCal Geothermal Inc., a wholly owned subsidiary of the Company
OrCal Senior Secured Notes	$165,000,000 6.21% Senior Secured Notes, due 2020 issued by OrCal
Organic Rankine Cycle	A process in which an organic fluid such as a hydrocarbon or fluorocarbon (but not water) is boiled in an evaporator to generate high pressure vapor. The vapor powers a turbine to generate mechanical power. After the expansion in the turbine, the low pressure vapor is cooled and condensed back to liquid in a condenser. A cycle pump is then used to pump the liquid back to the vaporizer to complete the cycle. The cycle is illustrated in the figure below:
Ormat International	Ormat International Inc., a wholly owned subsidiary of the Company
Ormat Nevada	Ormat Nevada Inc., a wholly owned subsidiary of the Company
Ormat Systems	Ormat Systems Ltd., a wholly owned subsidiary of the Company
ORPD	ORPD LLC, a holding company subsidiary of the Company in which Northleaf Geothermal Holdings, LLC holds a 36.75% equity interest
ORPD Transaction	Financing transaction involving the Puna complex and Don A. Campbell, OREG 1, OREG 2 and OREG 3 power plants in which Northleaf Geothermal Holdings, LLC purchased an equity interest in our special purpose subsidiary that owns such plants.
OrPower 4	OrPower 4 Inc., a wholly owned subsidiary of the Company
Ortitlan	Ortitlan Limitada, a wholly owned subsidiary of the Company
ORTP	ORTP, LLC, a consolidated subsidiary of the Company

Term	**Definition**
ORTP Transaction	Financing transaction involving power plants in Nevada and California in which an institutional equity investor purchased an interest in our special purpose subsidiary that owns such plants.
Orzunil	Orzunil I de Electricidad, Limitada, a wholly owned subsidiary of the Company
PEC	Portfolio Energy Credits
PG&E	Pacific Gas and Electric Company
PGV	Puna Geothermal Venture, a wholly owned subsidiary of the Company
PLN	PT Perusahaan Listrik Negara
Power plant equipment	Interconnection equipment, cooling towers for water cooled power plant, etc., including the generating units
PPA	Power purchase agreement
ppm	Part per million
PTC	Production tax credit
PUA	Israeli Public Utility Authority
PUCH	Public Utilities Commission of Hawaii
PUCN	Public Utilities Commission of Nevada
PUHCA	U.S. Public Utility Holding Company Act of 1935
PUHCA 2005	U.S. Public Utility Holding Company Act of 2005
PURPA	U.S. Public Utility Regulatory Policies Act of 1978
Qualifying Facility(ies)	Certain small power production facilities are eligible to be "Qualifying Facilities" under PURPA, provided that they meet certain power and thermal energy production requirements and efficiency standards. Qualifying Facility status provides an exemption from PUHCA 2005 and grants certain other benefits to the Qualifying Facility
RAM	Renewable Auction Mechanism
REC	Renewable Energy Credit
REG	Recovered Energy Generation
RGGI	Regional Greenhouse Gas Initiative
RPM	Revolutions Per Minute
RPS	Renewable Portfolio Standards
SCPPA	Southern California Public Power Authority
SEC	U.S. Securities and Exchange Commission
Securities Act	U.S. Securities Act of 1933, as amended
Senior Unsecured Bonds	7% Senior Unsecured Bonds Due 2017 issued by the Company
SO#4	Standard Offer Contract No. 4
Solar PV	Solar photovoltaic
SOX Act	Sarbanes-Oxley Act of 2002
Southern California Edison	Southern California Edison Company
SPE(s)	Special purpose entity(ies)
SRAC	Short Run Avoided Costs
Union Bank	Union Bank, N.A.
U.S.	United States of America
U.S. Treasury	U.S. Department of the Treasury
WHOH	Waste Heat Oil Heaters

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Cautionary Note Regarding Forward-Looking Statements

This annual report includes “forward-looking statements” within the meaning of the Private Securities Litigation Reform Act of 1995. All statements, other than statements of historical facts, included in this report that address activities, events or developments that we expect or anticipate will or may occur in the future, including such matters as our projections of annual revenues, expenses and debt service coverage with respect to our debt securities, future capital expenditures, business strategy, competitive strengths, goals, development or operation of generation assets, market and industry developments and the growth of our business and operations, are forward-looking statements. When used in this annual report, the words “may”, “will”, “could”, “should”, “expects”, “plans”, “anticipates”, “believes”, “estimates”, “pr “projects”, “potential”, or “contemplate” or the negative of these terms or other comparable terminology are intended to identify forward-looking statements, although not all forward-looking statements contain such words or expressions. The forward-looking statements in this annual report are primarily located in the material set forth under the headings Item 1 — “Business” contained in Part I of this annual report, Item 1A — “Risk Factors” contained in Part I of this annual report, Item 7 — “Management’s Discussion and Analysis of Financial Condition and Results of Operations” contained in Part II of this annual report, and “Notes to Financial Statements” contained in Item 8 — “Financial Statements and Supplementary Data” contained in Part II of this annual report, but are found in other locations as well. These forward-looking statements generally relate to our plans, objectives and expectations for future operations and are based upon management’s current estimates and projections of future results or trends. Although we believe that our plans and objectives reflected in or suggested by these forward-looking statements are reasonable, we may not achieve these plans or objectives. You should read this annual report completely and with the understanding that actual future results and developments may be materially different from what we expect due to a number of risks and uncertainties, many of which are beyond our control. Other than as required by law, we will not update forward-looking statements even though our situation may change in the future.

Specific factors that might cause actual results to differ from our expectations include, but are not limited to:

- significant considerations, risks and uncertainties discussed in this annual report;
- geothermal resource risk (such as the heat content, useful life and geological formation of the reservoir);
- operating risks, including equipment failures and the amounts and timing of revenues and expenses;
- financial market conditions and the results of financing efforts;
- the impact of fluctuations in oil and natural gas prices on the energy price component under certain of our PPAs;
- risks and uncertainties with respect to our ability to implement strategic goals or initiatives in segments of the clean energy industry or new or additional geographic focus areas;
- environmental constraints on operations and environmental liabilities arising out of past or present operations, including the risk that we may not have, and in the future may be unable to procure, any necessary permits or other environmental authorizations;

construction or other project delays or cancellations;

political, legal, regulatory, governmental, administrative and economic conditions and developments in the United States and other countries in which we operate and, in particular, the impact of recent and future federal, state and local regulatory proceedings and changes, including legislative and regulatory initiatives regarding deregulation and restructuring of the electric utility industry, public policies and government incentives that support renewable energy and enhance the economic feasibility of our projects at the federal and state level in the United States and elsewhere, and carbon-related legislation;

the enforceability of the long-term PPAs for our power plants;

contract counterparty risk;

weather and other natural phenomena including earthquakes, volcanic eruption, drought and other natural disasters;

changes in environmental and other laws and regulations to which our company is subject, as well as changes in the application of existing laws and regulations;

current and future litigation;

our ability to successfully identify, integrate and complete acquisitions;

competition from other geothermal energy projects and new geothermal energy projects developed in the future, and from alternative electricity producing technologies;

market or business conditions and fluctuations in demand for energy or capacity in the markets in which we operate;

the direct or indirect impact on our company's business of various forms of hostilities including the threat or occurrence of war, terrorist incidents or cyber-attacks or responses to such threatened or actual incidents or attacks, including the effect on the availability of and premiums on insurance;

our new strategic plan to expand our geographic markets, customer base and product and service offerings may not be implemented as currently planned or may not achieve our goals as and when the plan is implemented;

the effect of and changes in current and future land use and zoning regulations, residential, commercial and industrial development and urbanization in the areas in which we operate; and

other uncertainties which are difficult to predict or beyond our control and the risk that we may incorrectly analyze these risks and forces or that the strategies we develop to address them may be unsuccessful.

PART I

ITEM 1. BUSINESS

Certain Definitions

Unless the context otherwise requires, all references in this annual report to "Ormat", "the Company", "we", "us", "our company", "Ormat Technologies", or "our" refer to Ormat Technologies, Inc. and its consolidated subsidiaries. A glossary of certain terms and abbreviations used in this annual report appears at the beginning of this report.

Overview

We are a leading vertically integrated company primarily engaged in the geothermal and recovered energy power business. With the objective of becoming a leading global provider of renewable energy, we are focused on several key initiatives, which directly align with our new strategic plan, as described below.

We design, develop, build, own, and operate clean, environmentally friendly geothermal and recovered energy-based power plants, usually using equipment that we design and manufacture.

Our geothermal power plants include both power plants that we have built and power plants that we have acquired, while we have built all of our recovered energy-based plants. We currently conduct our business activities in the following two business segments:

- The Electricity segment — in this segment we develop, build, own and operate geothermal and recovered energy-based power plants in the U.S. and geothermal power plants in other countries around the world and sell the electricity they generate; and

- The Product segment — in this segment we design, manufacture and sell equipment for geothermal and recovered energy-based electricity generation, remote power units and other power generating units and provide services relating to the engineering, procurement, construction, operation and maintenance of geothermal and recovered energy-based power plants.

The map below shows our worldwide portfolio of operating geothermal and recovered energy power plants as of February 23, 2016.

The charts below show the relative contributions of the Electricity segment and the Product segment to our consolidated revenues and the geographical breakdown of our segment revenues for our fiscal year ended December 31, 2015. Additional information concerning our segment operations, including year-to-year comparisons of revenues, the geographical breakdown of revenues, cost of revenues, results of operations, and trends and uncertainties is provided below in Item 7 — "Management's Discussion and Analysis of Financial Condition and Results of Operations" and Item 8 — "Financial Statements and Supplementary Data".

The following chart sets forth a breakdown of our revenues for each of the years ended December 31, 2015 and 2014:

Segment Contribution to Revenues

The following chart sets forth the geographical breakdown of revenues attributable to our Electricity and Product segments for each of the years ended December 31, 2015 and 2014:

Geographical Breakdown of the

Electricity Segment Revenues

Geographical Breakdown of the

Product Segment Revenues

Most of the power plants that we currently own or operate produce electricity from geothermal energy sources. Geothermal energy is a clean, renewable and generally sustainable form of energy derived from the natural heat of the earth. Unlike electricity produced by burning fossil fuels, electricity produced from geothermal energy sources is produced without emissions of certain pollutants such as nitrogen oxide, and with far lower emissions of other pollutants such as carbon dioxide. As a result, electricity produced from geothermal energy sources contributes significantly less to global warming and local and regional incidences of acid rain than energy produced by burning fossil fuels. In addition, compared to some other renewable energy sources, such as wind or solar, geothermal is a firm and flexible form of energy and is generally available all the time. Geothermal energy is also an attractive alternative to other sources of energy as part of a national diversification strategy to avoid dependence on any one energy source or politically sensitive supply sources.

In addition to our geothermal energy business, we manufacture products that produce electricity from recovered energy or so-called “waste heat”. We also construct, own, and operate recovered energy-based power plants. Recovered energy comes from residual heat that is generated as a by-product of gas turbine-driven compressor stations, solar thermal units and a variety of industrial processes, such as cement manufacturing. Such residual heat, which would otherwise be wasted, may be captured in the recovery process and used by recovered energy power plants to generate electricity without burning additional fuel and without additional emissions.

During 2015, we refined and started to implement a number of the elements of a new multi-year strategic plan. We expect the plan to evolve over time in response to market conditions and other factors. At this time however, we expect that our primary focus will be as follows:

Expand our geothermal geographical reach. While we continue to evaluate opportunities worldwide, we currently see Mexico, Chile, Indonesia and Ethiopia as very attractive geothermal markets for us. We are actively looking at ways to expand our presence in those countries. In addition, we are looking to expand and accelerate growth through acquisition activities globally.

Expand into new technologies. We ultimately hope to be able to leverage our technological capabilities over a variety of renewable energy platforms, including solar power generation and energy storage. Initially, however, we expect that our focus will be on expanding our core geothermal competencies, such as expanding into more high temperature geothermal generation equipment and facilities. For example, we recently announced a new collaboration with Toshiba described below, which we anticipate may facilitate joint development of geothermal systems consisting of Ormat's binary system and Toshiba's flash system, among other things. We may acquire companies with technological and integration capabilities we do not currently have, or develop new technology ourselves, where we can effectively leverage our expertise to implement this part of our strategic plan.

Expand our customer base. We are evaluating a number of strategies for expanding our customer base to C&I customers. In the near term, however, we expect that a majority of our revenues will continue to be generated as they currently are, with our traditional electrical utility customer base for the Electricity segment and our on-going business development efforts for new customers for our Product segment.

While we believe that long-term growth can be realized through our transformational efforts over time, there is no assurance if and when we will meet our objective to become a leading global provider of renewable energy or that such efforts will result in long-term growth. To be clear, we see these new initiatives as incremental measures to enhance shareholder value. While we implement the plan, we expect to continue, and expand, through organic growth, acquisitions, and other measures, our current business lines both in the Electricity and Product segments as well as other business lines as described above.

Company Contact and Sources of Information

We file annual, quarterly and periodic reports, proxy statements and other information with the SEC. You may obtain and copy any document we file with the SEC at the SEC's Public Reference Room at 100 F Street, N.E., Room 1580, Washington D.C. 20549. You may obtain information on the operation of the SEC's Public Reference Room by calling the SEC at 1-800-SEC-0330. The SEC maintains an internet website at http://www.sec.gov that contains reports, proxy and other information statements, and other information regarding issuers that file electronically with the SEC. Our SEC filings are accessible via the internet at that website.

Our reports on Form 10-K, 10-Q and 8-K, and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Exchange Act are available through our website at www.ormat.com for downloading, free of charge, as soon as reasonably practicable after these reports are filed with the SEC. Our Code of Business Conduct and Ethics, Code of Ethics Applicable to Senior Executives, Audit Committee Charter, Corporate Governance Guidelines, Nominating and Corporate Governance Committee Charter, Compensation Committee Charter, and Insider Trading Policy, as amended, are also available at our website address mentioned above. If we make any amendments to our Code of Business Conduct and Ethics or Code of Ethics Applicable to Senior Executives or grant any waiver, including any implicit waiver, from a provision of either code applicable to our Chief Executive Officer, Chief Financial Officer or principal accounting officer requiring disclosure under applicable SEC rules, we intend to disclose the nature of such amendment or waiver on our website. The content of our website, however, is not part of this annual report.

You may request a copy of our SEC filings, as well as the foregoing corporate documents, at no cost to you, by writing to the Company address appearing in this annual report or by calling us at (775) 356-9029.

Our Power Generation Business (Electricity Segment)

Power Plants in Operation

The table below summarizes certain key non-financial information relating to our power plants as of February 23, 2016. The generating capacity of certain of our power plants listed below has been updated to reflect changes in the resource temperature and other factors that impact resource capabilities:

Type	Region	Plant	Ownership[1]	Generating capacity (MW) [2]	Region 2015 Capacity Factor
Geothermal	California	Ormesa Complex	100%	42[3]	
		Heber Complex	100%	92	
		Mammoth Complex	100%	29	
		North Brawley	100%	18	
					80%
	West Nevada	Steamboat Complex	100%	73	
		Brady Complex	100%	18	
					85%
	East Nevada	Tuscarora	100%	18	
		Jersey Valley	100%	10	
		McGinness Hills	100%	83[4]	
		Don A. Campbell	100%[5]	41[4]	
					96%
	Hawaii	Puna	100%[5]	38	
					69%
	International	Amatitlan	100%	20	
		Zunil	97%	23	
		Olkaria III Complex	100%	139[6]	
					96%
Total Geothermal				644	87%
REG		OREG 1	100%[5]	22	
		OREG 2	100%[5]	22	
		OREG 3	100%[5]	5.5	
		OREG 4	100%	3.5[7]	
Total REG				53	77%
Total				**697**	

(1) We indirectly own and operate all of our power plants, although financial institutions hold equity interests in three of our consolidated subsidiaries: (i) OPC, which owns the Desert Peak 2 power plant in our Brady complex and the Steamboat Hills, Galena 2 and Galena 3 power plants in our Steamboat complex; (ii) ORTP, which owns the Heber complex, the Ormesa complex, the Mammoth complex, the Steamboat 2 and 3 and Burdette (Galena 1) power plants both in our Steamboat complex, and Brady power plant in our Brady complex; and (iii) ORPD, which owns the Puna power plant, the Don A. Campbell complex and the OREG 1, OREG 2 and OREG 3 power plants. In the above table, we show these power plants as being 100% owned because all of the generating capacity is owned by either OPC, ORTP or ORPD and we control the operation of the power plants. The nature of the equity interests held by the financial institutions is described below in Item 7 — “Management’s Discussion and Analysis of Financial Condition and Results of Operations” under the heading “OPC Transaction”, “ORTP Transaction”, and “ORPD Transaction”.

(2) References to generating capacity generally refer to the gross generating capacity less auxiliary power in the case of all of our existing power plants, except the Zunil power plant. We determine the generating capacity figures in these power plants by taking into account resource capabilities. In the case of the Zunil power plant, revenues are calculated based on a 24 MW capacity unrelated to the actual performance of the reservoir. This column represents

our net ownership in such generating capacity.

In any given year, the actual power generation of a particular power plant may differ from that power plant's generating capacity due to variations in ambient temperature, the availability of the resource, and operational issues affecting performance during that year.

(3) The generating capacity of the Ormesa complex was reduced in 2015 mainly due to a permanent shutdown of one of the steam turbines and some of the old OECs in order to optimize plant performance.

(4) The McGinness phase 2 power plant reached commercial operation on February 1, 2015. The Don A. Campbell phase 2 power plant reached commercial operation on September 17, 2015. The generating capacities of both complexes are higher than originally expected.

(5) On April 30, 2015, we announced the closing of an equity transaction with Northleaf Geothermal Holdings, LLC. Pursuant to the purchase agreement, Northleaf acquired a 36.75% equity interest in ORPD which owns the Puna complex and the Don A. Campbell, OREG 1, OREG 2 and OREG 3 power plants. See Item 7 - "Management's Discussion and Analysis of Financial Condition and Results of Operations" under the heading "ORPD transaction".

(6) Plant 4 in the Olkaria III complex reached commercial operation on January 18, 2016 increasing the complex's capacity by 29 MW to 139 MW.

(7) The OREG 4 power plant is not operating at full capacity as a result of continued low run time of the compressor station that serves as the plant's heat source. This results in lower power generation.

All of the revenues that we derive from the sale of electricity are pursuant to long-term PPAs. Approximately 40.5% of our total revenues in the year ended December 31, 2015 were derived from the sale of electricity by our domestic power plants to power purchasers that currently have investment grade credit ratings. The purchasers of electricity from our foreign power plants are either state-owned or private entities.

New Power Plants

We are currently in various stages of construction and development of new power plants and expansion of existing power plants. Our expansion plan includes 49 MW in generating capacity from geothermal power plants in Honduras and Indonesia that are fully released for construction and are in different stages of construction. In addition, we have several projects worldwide that are either under initial stages of construction or under different stages of development with an aggregate capacity of up to approximately 140 MW.

We have a substantial land position across 30 prospects in the U.S., Guatemala, New Zealand, Kenya, Chile and Ethiopia that are expected to support future geothermal development, on which we have started or plan to start exploration activity. This land position is comprised of various leases, exploration concessions for geothermal resources and an option to enter into geothermal leases.

Our Product Business (Product Segment)

We design, manufacture and sell products for electricity generation and provide the related services described below. We primarily manufacture products to fill customer orders, but in some situations we may manufacture products as inventory for future internal and external projects.

Power Units for Geothermal Power Plants. We design, manufacture and sell power units for geothermal electricity generation, which we refer to as OECs. In geothermal power plants using OECs, geothermal fluid (either hot water (also called brine) or steam or both) is extracted from the underground reservoir and flows from the wellhead to a vaporizer that also heats a secondary working fluid, which is vaporized and used to drive the turbine. The secondary fluid is then condensed in a condenser which may be cooled directly by air or by water from a cooling tower and sent back to the vaporizer. The cooled geothermal fluid is then reinjected back into the reservoir. Our customers include contractors and geothermal power plant developers, owners and operators.

Power Units for Recovered Energy-Based Power Generation. We design, manufacture and sell power units used to generate electricity from recovered energy, or so-called “waste heat”. This heat is generated as a residual by-product of gas turbine-driven compressor stations, solar thermal units and a variety of industrial processes, such as cement manufacturing, and is not otherwise used for any purpose. Our existing and target customers include interstate natural gas pipeline owners and operators, gas processing plant owners and operators, cement plant owners and operators, and other companies engaged in other energy-intensive industrial processes.

EPC of Power Plants. We engineer, procure, and construct, as an EPC contractor, geothermal and recovered energy power plants on a turnkey basis, using power units we design and manufacture. Our customers are geothermal power plant owners as well as our target customers for the sale of our recovered energy-based power units described above. Unlike many other companies that provide EPC services, we believe we have an advantage in that we are using our own manufactured equipment and thus have better quality and better control over the timing and delivery of required equipment and its related costs. As part of our new strategy and collaboration agreement with Toshiba we might have EPC contracts that are based on Toshiba power units. We also expect to develop additional knowledge in integrating Toshiba power units combined with our OECs in order to maximize the benefits to our customers.

Remote Power Units and Other Generators. We design, manufacture and sell fossil fuel powered turbo-generators with capacities ranging from 200 watts to 5,000 watts, which operate unattended in extreme hot or cold climate conditions. Our customers include contractors who install gas pipelines in remote areas and off-shore platforms operators and contractors. In addition, we design, manufacture, and sell generators, including heavy duty direct-current generators, for various other uses.

History

We were formed as a Delaware corporation in 1994 by Ormat Industries. Ormat Industries was one of the first companies to focus on the development of equipment for the production of clean, renewable and generally sustainable forms of energy. On February 12, 2015, we successfully completed the acquisition of Ormat Industries, eliminating its majority ownership and control of us. Our acquisition of Ormat Industries is described in greater detail below under “Recent Developments.”

Industry Background

Geothermal Energy

Most of our power plants in operation produce electricity from geothermal energy. There are several different sources or methods of obtaining geothermal energy, which are described below.

Hydrothermal geothermal-electricity generation — Hydrothermal geothermal energy is derived from naturally occurring hydrothermal reservoirs that are formed when water comes sufficiently close to hot rock to heat the water to temperatures of 300 degrees Fahrenheit or more. The heated water then ascends toward the surface of the earth where, if geological conditions are suitable for its commercial extraction, it can be extracted by drilling geothermal wells. Geothermal production wells are normally located within several miles of the power plant, as it is not economically viable to transport geothermal fluids over longer distances due to heat and pressure loss. The geothermal reservoir is a renewable source of energy if: (i) natural ground water sources and reinjection of extracted geothermal fluids are adequate over the long-term to replenish the geothermal reservoir following the withdrawal of geothermal fluids and (ii) the well field is properly operated. Geothermal energy power plants typically have higher capital costs (primarily as a result of the costs attributable to well field development) but tend to have significantly lower variable operating costs (principally consisting of maintenance expenditures) than fossil fuel-fired power plants that require ongoing fuel expenses. In addition, because geothermal energy power plants produce weather-independent power 24 hours a day, the variable operating costs are lower.

EGS — An EGS is a subsurface system that may be artificially created to extract heat from hot rock where the permeability and aquifers required for a hydrothermal system are insufficient or non-existent. A geothermal power plant that uses EGS techniques recovers the thermal energy from the subsurface rocks by creating or accessing a system of open fractures in the rock through which water can be injected, heated through contact with the hot rock, returned to the surface in production wells and transferred to a power unit.

Co-produced geothermal from oil and gas fields, geo-pressurized resources — Another source of geothermal energy is hot water produced as a by-product of oil and gas extraction. When oil and gas wells are deep, the fluids are often at high temperatures and if the water volume is significant, the hot water can be used for power generation in equipment similar to a geothermal power plant.

Geothermal Power Plant Technologies

Geothermal power plants generally employ either binary systems or conventional flash design systems, as briefly described below. In our geothermal power plants, we also employ our proprietary technology of combined geothermal cycle systems.

Binary System

In a geothermal power plant using a binary system, geothermal fluid (either hot water (also called brine) or steam or both) is extracted from the underground reservoir and flows from the wellhead through a gathering system of insulated steel pipelines to a vaporizer that also heats a secondary working fluid. This is typically an organic fluid, such as pentane or butane, which is vaporized and is used to drive the turbine. The organic fluid is then condensed in a condenser which may be cooled directly by air or by water from a cooling tower and sent back to the vaporizer. The cooled geothermal fluid is then reinjected back into the reservoir. Ormat's air-cooled binary geothermal power plant is depicted in the diagram below.

Flash Design System

In a geothermal power plant using flash design, geothermal fluid is extracted from the underground reservoir and flows from the wellhead through a gathering system of insulated steel pipelines to flash tanks and/or separators. There, the steam is separated from the brine and is sent to a demister, where any remaining water droplets are removed. This produces a stream of dry saturated steam, which drives a steam turbine generator to produce electricity. In some cases, the brine at the outlet of the separator is flashed a second time (dual flash), providing additional steam at lower pressure used in the low pressure section of the steam turbine to produce additional electricity. Steam exhausted from the steam turbine is condensed in a surface or direct contact condenser cooled by cold water from a cooling tower. The non-condensable gases (such as carbon dioxide) are removed by means of a vacuum system in order to maintain the performance of the steam condenser. The resulting condensate is used to provide make-up water for the cooling tower. The hot brine remaining after separation of steam is injected (either directly or after passing through a binary plant to produce additional power from the residual heat remaining in the brine) back into the geothermal resource through a series of injection wells. The flash technology is depicted in the diagram below.

In some instances, the wells directly produce dry steam and the steam is fed directly to the steam turbine with the rest of the system similar to the flash power plant described above.

Our Proprietary Technology

Our proprietary technology may be used in power plants operating according to the Organic Rankine Cycle, either alone or in combination with various other commonly used thermodynamic technologies that convert heat to mechanical power, such as gas and steam turbines. It can be used with a variety of thermal energy sources, such as geothermal, recovered energy, biomass, solar energy and fossil fuels. Specifically, our technology involves original designs of turbines, pumps, and heat exchangers, as well as formulation of organic motive fluids (all of which are non-ozone-depleting substances). Using advanced computerized fluid dynamics and other computer aided design software as well as our test facilities, we continuously seek to improve power plant components, reduce operations and maintenance costs, and increase the range of our equipment and applications. We are always examining ways to increase the output of our plants by utilizing evaporative cooling, cold reinjection, performance simulation programs, and topping turbines. In the geothermal as well as the recovered energy (waste heat) areas, we are examining two-level and three-level energy systems and new motive fluids.

We also developed, patented and constructed GCCU power plants in which the steam first produces power in a backpressure steam turbine and is subsequently condensed in a vaporizer of a binary plant, which produces additional power. Ormat Geothermal Combined Cycle technology is depicted in the diagram below.

In the conversion of geothermal energy into electricity, our technology has a number of advantages over conventional geothermal steam turbine plants. A conventional geothermal steam turbine plant consumes significant quantities of water, causing depletion of the aquifer and requiring cooling water treatment with chemicals and thus a need for the disposal of such chemicals. A conventional geothermal steam turbine plant also creates a significant visual impact in the form of an emitted plume from the cooling towers, especially during cold weather. By contrast, our binary and combined cycle geothermal power plants have a low profile with minimum visual impact and do not emit a plume when they use air cooled condensers. Our binary and combined cycle geothermal power plants reinject all of the geothermal fluids utilized in the respective processes into the geothermal reservoir. Consequently, such processes generally have no emissions.

Other advantages of our technology include simplicity of operation, easy maintenance and higher yearly availability. For instance, the OEC employs a low speed and high efficiency organic vapor turbine directly coupled to the generator, eliminating the need for reduction gear. In addition, with our binary design, there is no contact between the turbine blade and geothermal fluids, which can often be very corrosive and erosive. Instead, the geothermal fluids pass through a heat exchanger, which is less susceptible to erosion and can adapt much better to corrosive fluids. In addition, with the organic vapor condensed above atmospheric pressure, no vacuum system is required.

We use the same elements of our technology in our recovered energy products. The heat source may be exhaust gases from a Brayton cycle gas turbine, low pressure steam, or medium temperature liquid found in the process industries such as oil refining and cement manufacturing. In most cases, we attach an additional heat exchanger in which we circulate thermal oil or water to transfer the heat into the OEC’s own vaporizer in order to provide greater operational flexibility and control. Once this stage of each recovery is completed, the rest of the operation is identical to that of the OECs used in our geothermal power plants and enjoys the same advantages of using the Organic Rankine Cycle. In addition, our technology allows for better load following than conventional steam turbines, requires no water treatment (since it is air cooled and organic fluid motivated), and does not require the continuous presence of a licensed steam boiler operator on site.

Ormat's REG technology is depicted in the diagram below.

Patents

We have 72 U.S. patents that are in force (and have approximately 30 U.S. patents pending). These patents and patent applications cover our products (mainly power units based on the Organic Rankine Cycle) and systems (mainly geothermal power plants and industrial waste heat recovery plants for electricity production). The products-related patents cover components that include turbines, heat exchangers, seals and controls as well as control of operation of geothermal production well pumps. The system-related patents cover not only particular components but also the overall energy conversion system from the "fuel supply" (e.g., geothermal fluid, waste heat, biomass or solar) to electricity production.

The system-related patents cover subjects such as waste heat recovery related to gas pipeline compressors and industrial waste heat, disposal of non-condensable gases present in geothermal fluids, power plants for very high pressure geothermal resources, two-phase fluids as well as processes related to EGS. A number of our patents cover combined cycle geothermal power plants, in which the steam first produces power in a backpressure steam turbine and is subsequently condensed in a vaporizer of a binary plant, which produces additional power. The remaining terms of our patents range from one year to 18 years. The loss of any single patent would not have a material effect on our business or results of operations.

Research and Development

We are conducting research and development activities intended to improve plant performance, reduce costs, and increase the breadth of our product offerings. The primary focus of our research and development efforts is targeting power plant conceptual thermodynamic cycle and major equipment including continued performance, cost and land usage improvements to our condensing equipment, and development of new higher efficiency and higher power output turbines.

Additionally, we are continuing to evaluate investment opportunities in new companies with technology and/or product offerings for renewable energy and energy storage solutions.

Market Opportunity

United States

Interest in geothermal energy in the U.S. remains strong for numerous reasons, including legislative support of RPS, coal and nuclear base load energy retirement and increasing awareness of the positive value of geothermal characteristics as compared to intermittent renewable technology.

Today, electricity generation from geothermal resources is concentrated mainly in California, Nevada, Hawaii, Idaho and Utah, and we believe there are opportunities for development in other states such as Arizona, New Mexico, Washington and Oregon due to the potential of their geothermal resources.

In a report issued in February 2015, the GEA indicated that the U.S. geothermal industry had about 3,500 MW of installed nameplate capacity and about 1,250 MW of geothermal projects under various phases of consideration or development in 10 U.S. states.

The U.S. geothermal market experienced modest growth mainly, according to the GEA, due to the uncertainty surrounding the federal PTC for new projects combined with unbalanced mechanisms for valuing baseload power and integration costs in California (where a significant amount of U.S. geothermal resources are located).

The successful implementation of the various confirmed and unconfirmed geothermal projects identified by the GEA depends on the respective project sponsor’s ability to fully identify the resource, conduct exploration, and carry out development and construction. Accordingly, the GEA estimates may not be realized, and differences between the actual number of projects completed and those initially estimated to be completed may be material. We refer to the GEA assessment as a possible reference point, but we do not necessarily concur with its estimate.

State level legislation

One of the factors supporting growth in the renewable energy industry is global concern about climate change. In response to increasing demand for “green” energy, many countries have adopted legislation requiring, and providing incentives for, electric utilities to sell electricity generated from renewable energy sources. In the U.S., 38 states and four territories have enacted an RPS, renewable portfolio goals, or similar laws requiring or encouraging utilities in such states to generate or buy a certain percentage of their electricity from renewable energy or recovered heat sources.

According to the Database of State Incentives for Renewables and Efficiency (DSIRE), 30 states and two territories (including California, Nevada, and Hawaii, where we have been the most active in our geothermal energy development and in which all of our operating U.S. geothermal power plants are located) and the District of Columbia define geothermal resources as “renewable”. In addition, according to the EPA, 25 states have enacted RPS, Clean Energy Standards, Energy Efficiency Resource Standards or Alternative Portfolio Standards program guidelines that include some form of combined heat and power and/or waste heat recovery.

We see the impact of RPS legislation as the most significant driver for us to expand existing power plants and to build new projects.

California

The California RPS was established in 2002 under Senate Bill (SB) 1078 accelerated in 2006 under SB 107 and further expanded in 2011 under SB(x)1-2. The RPS program requires investor-owned utilities (IOUs), electric service providers, community choice aggregators and publicly-owned utilities to increase their share of procurement from eligible renewable energy resources as a percentage of their total procurement. The RPS goal of 33 percent by 2020 was revised in October 2015, when Governor Jerry Brown signed into law SB 350 requiring that 50 percent of total retail electricity sales be from renewable resources by 2030, with interim targets of 40 percent by 2024, and 45 percent by 2027.

According to the CPUC Biennial RPS Program Update published in January 2016, California's three largest IOUs collectively generated 26.6% of their 2014 retail electricity sales from renewable resources. These utilities have interim targets each year, with a requirement to attain RPS of 25% by 2016. Publicly-owned utilities in California are also required to procure 50% of retail electricity sales from eligible renewable energy resources by 2030, opening up an additional market of potential off-takers for us. This expanded target could benefit geothermal energy, which has the advantage of generating flexible base load power, and helping California diversify its mix of renewable resources.

In 2006, California passed a state climate change law, Assembly Bill (AB) 32, to reduce GHG emissions to 1990 levels by the end of 2020, and in December 2010, the CARB approved cap-and-trade regulations to reduce California's GHG emissions below the levels set by AB 32. The regulations set a limit on emissions from sources responsible for emitting 80% of California's GHGs. On November 2015, the CARB released the results of its fifth joint auction for California and Québec allowances reporting that the vintage 2015 auction clearing price was $12.73 per allowance and the future vintage auction clearing price was $12.65 per allowance. All of the available 2015 and future vintage allowances offered were sold.

In 2014, AB 2363 became effective, requiring the CPUC to adopt by December 31, 2015 a methodology for determining the costs of integrating eligible renewable energy resources. As of the date of this report no methodology has been adopted.

Nevada

Nevada's RPS was first adopted by the Nevada Legislature in 1997. Nevada's RPS targets were revised and expanded and currently require NV Energy to supply at least 25% of the total electricity it sells from eligible renewable energy resources by 2025. For each of 2013 and 2014, Nevada's RPS required that at least 18% of electricity sold to Nevada retail customers be from renewable energy resources and credits, and at least 5% of that amount be from solar resources. According to NV Energy's Annual RPS Compliance Report, in 2014, Nevada Power exceeded both the 2014 RPS requirement and the 2014 solar RPS requirement, achieving 20.2% and 32.8%, respectively. Sierra exceeded both the 2014 RPS requirement and the 2014 solar RPS requirement, with 33.6% and 20.6% respectively.

In June 2013, the Nevada state legislature passed three bills that were signed into law and expected to support renewable energy development. SB No. 123 requires an electric utility to submit a plan for the retirement or elimination of not less than 800 MW of coal-fired electric generating capacity on or before December 31, 2019 and the construction or acquisition of, or contracting for, 350 MW of electric generating capacity from renewable energy facilities. SB No. 252 revises provisions relating to the renewable portfolio standard by removing energy efficiency, solar multipliers, and station usage from generating portfolio energy credits (PECs). Finally, AB No. 239 Revised Statutes 701A.340 defines geothermal energy as renewable energy for purposes of tax abatements and makes geothermal projects eligible to apply for partial sales and property tax abatements, with property tax abatements for 20 years and local sales and use tax abatements for three years.

Hawaii

Hawaii established a renewable portfolio goal in 2001. Since 2001, the RPS targets were revised and expanded. On June 2015, Hawaii became the only state with a legislative goal of 100% renewable energy by 2045 with the signing of HB 623. The new policy includes interim requirements of 15% by the end of 2015, 30% by the end of 2020, 40% by 2030, and 70% by 2040, ultimately reaching 100% renewable electricity by 2045.

According to a 2015 filing made with the PUCH, in 2014, Hawaiian Electric Company and its subsidiaries exceeded the 2014 RPS requirement, achieving a consolidated RPS of 38.6% of retail electricity sales from eligible renewable energy resources, including electrical energy savings from energy efficiency and solar water heating technologies. Excluding electrical energy savings from energy efficient and solar water heating technologies, the 2014 renewable generation percentage for the Hawaiian Electric Companies was 21.3%.

Other States

Other state-wide and regional initiatives are also being developed to reduce GHG emissions and to develop trading systems for renewable energy credits. For example, nine Northeast and Mid-Atlantic States are part of the RGGI, a regional cap-and-trade system to limit carbon dioxide. The RGGI is the first, market-based carbon dioxide emissions reduction program in the U.S. The RGGI states implemented a new 2014 RGGI cap of 91 million short tons and plan to reduce carbon emissions from power plants at a rate of 2.5% per year between 2015 and 2020. States sell nearly all emission allowances through auctions and invest proceeds in energy efficiency, renewable energy and other consumer benefit programs. These programs are spurring innovation in the clean energy economy and creating green jobs in the RGGI states.

In addition to RGGI, other states have also established the Midwestern Regional Greenhouse Gas Reduction Accord (Midwest Accord) and the Western Climate Initiative (WCI). The RGGI, the WCI and the Midwest Accord have formed the North America 2050, a Partnership for Progress (NA2050) that facilitates state and provincial efforts to design, promote and implement cost-effective policies that reduce GHG emissions and create economic opportunities.

Although individual and regional programs will take some time to develop, their requirements, particularly the creation of any market-based trading mechanism to achieve compliance with emissions caps, should be advantageous to in-state and in-region (and, in some cases, such as RGGI and the State of California, inter-regional) energy generating sources that have low carbon emissions such as geothermal energy.

In December 2015, the White House announced that 154 companies from across the American economy signed the American Business Act on Climate Pledge to demonstrate their support for action on climate change. By signing the American Business Act on Climate pledge, these companies are demonstrating an ongoing commitment to climate action. As part of this initiative, each company is announcing significant pledges to reduce their emissions, increase low-carbon investments, deploy more clean energy, and take other actions to build more sustainable businesses and tackle climate change.

Although it is currently difficult to quantify the direct economic benefit of these efforts to reduce GHG emissions, we believe they will prove advantageous to us.

Federal level legislation

On August 3, 2015, President Obama and the EPA announced the Clean Power Plan that sets standards for power plants and customized goals for states to cut the carbon pollution that is driving climate change. The goal of the proposed plan includes cutting carbon emissions from the power sector by 32% below 2005 levels nationwide by 2030. We believe that if the Clean Power Plan inserted, it will create demand for renewables in states that have untapped geothermal potential like Utah and New Mexico. States are given flexibility to meet these goals, but are required to submit implementation plans to the EPA by September 6, 2016 or request extensions to submit implementation plans by September 6, 2018. The EPA is also developing a federal plan and will implement a plan for those states that fail to submit an implementation plan or fail to get an approved plan. In February 2016, the Supreme Court of the U.S. granted a temporary stay halting implementation of the Clean Power Plan pending resolution of legal challenges to the proposed plan.

The federal government also encourages production of electricity from geothermal resources or solar energy through certain tax subsidies. For a new geothermal power plant in the U.S. that started construction by December 31, 2016, we are permitted to claim an investment tax credit against our U.S. federal income taxes equal to 30% of certain eligible costs when the project is placed in service. If we failed to meet the start of construction deadline for such a project, then the 30% credit is reduced to 10%. In lieu of the 30% investment tax credit (if the project qualifies), we are permitted to claim production tax credits which are based on the power produced from a geothermal power plant. These production-based credits, which in 2015 were 2.3 cents per kWh, may be adjusted annually for inflation and may be claimed for ten years on the electricity produced by the project and sold to third parties after the project is placed in service. The owner of the power plant may not claim both the 30% investment tax credit and the production-based tax credit. New solar projects that are under construction by December 2019 will qualify for a 30% investment tax credit. The credit will fall to 26% for projects starting construction in 2020 and 22% for projects starting construction in 2021. Projects that are under construction before these deadlines must be placed in service by December 2023 to qualify. The investment credit will revert to its permanent 10% level after that. Under current tax rules, any unused tax credit has a one-year carry back and a twenty-year carry forward.

We are also permitted to depreciate, or write off, most of the cost of the plant. In those cases where we claimed the one-time 30% (or 10%) tax credit or received the Treasury cash grant, our tax basis in the plant that we can recover through depreciation is reduced by one-half of the tax credit or cash grant; if in the future we claim other tax credits, there is no reduction in the tax basis for depreciation. For projects that we placed into service after September 8, 2010 and before January 1, 2012, a depreciation “bonus” will permit us to write off 100% of the cost of certain equipment that is part of the geothermal power plant in the year the plant is placed into service, if certain requirements are met. For projects that are placed into service after December 31, 2011 and before January 1, 2017, a similar “bonus” will permit us to write off 50% of the cost of that equipment in the year the power plant is placed into service. New equipment put in service in 2018 would qualify for a 40% bonus. Equipment put in service in 2019 would qualify for a 30% bonus. After applying any depreciation bonus that is available, we can write off the remainder of our tax basis in the plant, if any, over five years on an accelerated basis, meaning that more of the cost may be deducted in the first few years than during the remainder of the depreciation period.

Collectively, these benefits (to the extent they are fully utilized) have a present value equivalent to approximately 30% to 40% of the capital cost of a new power plant.

Global

We believe the global markets continue to present growth and expansion opportunities in both established and emerging markets.

According to the GEA’s Annual U.S. and Global Geothermal Power Production Report, the global geothermal market was developing about 11.5-12.3 GW of planned capacity spread across 80 countries. Additionally, the GEA estimates that, based on current data, the global geothermal industry is expected to reach between 14.5 GW and 17.6 GW by 2020.

The assessment conducted by the GEA is only an estimate that is based on projects and resource reporting by the geothermal industry. A developer's ability to fully develop a geothermal resource is dependent upon its capabilities to identify the resource and conduct exploration, development and construction; therefore, this estimate may not be accurate. We refer to it only as a possible reference point, but we do not necessarily concur with this estimate.

Operations outside of the U.S. may be subject to and/or benefit from increasing efforts by governments and businesses around the world to flight climate change and move towards a low carbon, resilient and sustainable future.

In December 2015, 195 countries signed an historic agreement at the COP21 UN Climate Change Conference held in Paris. For the first time, all countries committed to setting nationally determined climate targets and reporting on their progress. The agreement's aim is to keep global temperature rise this century well below 2 degrees Celsius and to drive efforts to limit the temperature increase even further to 1.5 degrees Celsius above pre-industrial levels. According to the United Nations Framework Convention on Climate Change (UNFCCC),the submission of national targets in five-year cycles signals to investors and technology innovators that the world will demand clean power plants, energy efficient factories and buildings, and low-carbon transportation in the decades to come.

In November 2015, a group of 20 countries, including the US, UK, France, China and India, pledged to double their budget for renewable energy technology over the next five years as part of a separate initiative called Mission Innovation.

Also in November 2015, the Breakthrough Energy Coalition was launched by a group of 28 private investors with the objective of bringing companies with the potential to deliver affordable, reliable and carbon free power from the research lab to the market.

We believe that these developments and governmental plans will create opportunities for us to acquire and develop geothermal power generation facilities internationally, as well as create additional opportunities for our Product segment.

Outside of the U.S., the majority of power generating capacity has historically been owned and controlled by governments. Since the early 1990s, however, many foreign governments have privatized their power generation industries through sales to third parties encouraging new capacity development and/or refurbishment of existing assets by independent power developers. These foreign governments have taken a variety of approaches to encourage the development of competitive power markets, including awarding long-term contracts for energy and capacity to independent power generators and creating competitive wholesale markets for selling and trading energy, capacity, and related products. Some foreign regions and countries have also adopted active government programs designed to encourage clean renewable energy power generation such as the following countries in which we operate and/or are conducting business development activities:

Europe

Turkey has the richest known geothermal resources in Europe with the theoretical potential for 31,000 MW of geothermal capacity and with a proven geothermal capacity of 4.5 GW, according to the Turkish Mineral Technical Exploration Agency (MTA).

Since 2004, we have established strong relationships in the Turkish market and provided our full range of solutions including our supply of state-of-the-art binary systems to 17 geothermal power plants with a total capacity of nearly 300 MW and 5 power plants under construction.

In Turkey, the 'National Renewable Energy Action Plan' proposes to increase the country's renewable energy generation capacity to 61 GW by 2023, including 1.5 GW of geothermal. The plan is supported by the European Bank for Reconstruction and Development (EBRD). The plan aims to increase Turkish energy security by diversifying its energy supply, make greater use of domestic resources, protect the environment by relying on clean, renewable and low carbon technologies and foster energy market efficiency through private sectors investment and integration.

The plan also seeks to attract private investments in research and development and in geothermal exploitation for electricity production and to provide financial support to innovation and technology research in the field of renewable energies. Special emphasis and attention has been placed on using locally manufactured equipment in renewable energy based generating facilities, with a target set for 45% of equipment used in such facilities by the end of 2019 to be manufactured locally.

To achieve its objective of having 30% of its power generated from renewable sources by 2023, Turkey has changed the renewable energy law first enacted in 2007. The law sets the feed-in tariffs (FITs) for geothermal energy at $105 per MWh. The FITs apply for a ten-year period from the date of commissioning. Renewable energy producers will also benefit from an 85% discount on transmission costs for 10 years and various priority rights over land usage. In order to benefit from the incentives under the renewable energy law, a renewable energy generation facility must hold a renewable energy resource certificate (the RER Certificate), which is issued by Turkey's Energy Market Regulatory Authority (EMRA). The RER Certificate will be valid for the term of the generation license of the relevant generation company. In addition, and to avoid rights and licenses manipulation, a pre-feasibility license must be issued and paid for upon the request to hold a concession. These pre-licenses must be turned into full licenses for developed fields within three years of issuance, or they become void and the license rights may be re-assigned. The current law allows FITs to be applied to projects that will be put into operation until October 2020. In addition, in the event that a developer uses locally sourced equipment in its plant, a premium will be added into the tariffs.

Latin America

Several Latin American countries have renewable energy programs. In November 2013, the national government of **Guatemala**, where our Zunil and Amatitlan power plants are located, approved a law creating incentives for power generation from renewable energy sources. These incentives include, among other things, providing economic and fiscal incentives such as exemptions from taxes on the importation of relevant equipment and various tax exemptions for companies implementing renewable energy projects. Additionally, the Energy Policy 2013-2027 identifies great untapped potential for renewable energy production in Guatemala, including 1,000 MW for geothermal. One of the main objectives of the Energy Policy is to secure a supply of electricity at competitive prices by diversifying the energy mix with an 80% renewable energy share target for 2027.

In **Honduras**, where we are planning to build the first geothermal power plant under a BOT agreement, the national government approved the Incentives Act (Decree No.70-2007) providing incentives in the form of tax exemptions for equipment, materials and services related to power generation development based on renewable resources. At the same time, ENEE, the national integrated utility, will buy energy from such projects and offer to pay rates that are above the marginal cost approved by the CNE. Honduras also set a target to reach at least 80% renewable energy production by 2034.

In **Chile**, where we have one exploration concession, the Chilean Renewable Energy Act of 2008 required 5% of electricity sold, to come from renewable sources, increasing gradually to 10% by 2024. On October 14, 2013, the President of Chile signed into law a bill which mandates that utilities source 20% of their electricity from "non-conventional" renewable energy (ERNC), including solar PV and concentrating solar power (CSP), by 2025.

Mexico is the world's fourth largest producer of geothermal energy. Recent studies suggest an over 9,000 MW geothermal potential, of which only 12% is already developed. In December 2013, the Mexican Congress passed a constitutional reform (Energy Reform) in an attempt to increase the participation of private investors in the generation and commercialization of electric energy. This reform affects the electricity market by opening the generation and commercialization of electricity to private companies, transforming the Federal Electricity Commission to a for-profit public company, and redefining the functions and attributions of the Ministry of Energy. The secondary legislation that establishes the attributions of the public entities, procurement regulations, and normative framework for the productive State companies was finalized in 2014.

In July 2015, **Mexico** launched round zero and assigned the projects to be developed by Mexico's state-owned utility Comision Federal de Electricidad (CFE), with the remainder to be put out to tender to the private sector. Thirteen geothermal areas and five concessions were given by the Mexican Secretariat of Energy (Sener) to the CFE. The government expects to award private companies with concessions for 30 years and permits for up to 150 km^2 for three years in the case of exploration. Ormat is in various discussions with local companies to identify attractive geothermal resources and projects.

Many **island** nations in general and specifically the **Caribbean** nations, depend almost entirely on petroleum to meet their electricity demands. With an average electricity price of US$35 per MWh in 2014, the lack of diversified power generation leaves Caribbean nations vulnerable to commodity market volatility, while the lack of new development leaves them reliant on what are believed to be outdated and often unreliable power plants. The larger issue hindering large-scale renewable energy deployments, however, is scale. Caribbean nations have quite significant renewable energy potential yet most have small demand. The majority of the Caribbean grids are relatively old, with the average diesel generators more than 20 years old. Furthermore, the power supply is relatively inefficient with high system losses. Due to their sizes, each of the Caribbean countries is generally dominated by one local utility and simple market structures where electricity is regulated directly by local governments. Other than in Guadeloupe, where a geothermal power plant that we recently signed a memorandum of understanding (MOU) to acquire has been operating since 1985, there are no other operating geothermal projects in the Caribbean region. Recently, some deep well drilling exploration was performed on a few islands, but the results of this exploration are still pending. Although few, we believe there are opportunities for us in the Caribbean.

Oceania

In **New Zealand**, where we have been actively providing geothermal power plant solutions since 1988, the New Zealand government's policies to fight climate change include an unconditional GHG emissions reduction target of between 10% and 20% below 1990 levels by 2020 and a target to increase renewable electricity generation to 90% of New Zealand's total electricity generation by 2025.

South East Asia

In **Indonesia**, where we participate in the Sarulla project that is currently under construction, the government intends to increase the role of renewable energy sources and aims to have them meet 23% of domestic energy demand by 2025. The government has also implemented new policies and regulations intended to accelerate the development of renewable energy and geothermal projects in particular. In June 2014, the Ministry of Energy and Mineral Resources (MEMR) issued a new geothermal tariff policy. The MEMR reverted to a location-based tariff regime while adding a time dimension. The tariffs range from $0.118 to $0.296 per kWh between 2015 and 2025, depending on location. The tariffs provide a ceiling price for the power purchase agreements between project developers and PLN, the national utility and off taker. The tariffs were set to include the effect of inflation on projects that are expected to commence commercial operation in the distant future.

In addition, the 2014 National Energy Policy (NEP) calls for the increased use of geothermal energy to represent at least 5% of the national energy mix by 2025.

In order to further accelerate geothermal development in the country a new FIT regime is expected to become effective during early 2016. The FIT is planned to range from $0.162 to $0.297 per kWh depending on size and location. Additionally, in January 2016, the government of Indonesia announced it will offer 21 geothermal blocks to investors over the next two years. Ormat plans to participate in select appropriate bids.

In the IPP sector, certain regulations for geothermal projects have been implemented, providing incentives such as investment tax credits, accelerated depreciation, and pricing guidelines to allow for preferential power prices for generators.

On January 2016, the President of Indonesia issued new presidential regulations (PR No. 4 2016) to accelerate the Indonesian 35 GW Power Generation Program. The regulations introduce a new government guarantee for development of power projects, which would cover both projects developed by the state-owned utility company, PLN, and those projects developed by PLN in cooperation with IPPs or their subsidiaries. Additionally, a shorter period to obtain necessary permits for development was introduced as well as clarifications that geothermal projects can be developed in high-conservation forest areas (e.g. national parks).

The Government of Indonesia is planning to revise negative investment regulation (DNI). According to Presidential Decree No. 39/2014, the development of geothermal power plants with a capacity of less than 10 MW is closed to foreign ownership. Currently, foreign investors may own up to 95 percent of plants with generating capacities greater than 10 MW. The revised regulations, currently under government review, will allow foreign entities to wholly own geothermal power plants with generating capacities greater than 10 MW and to own 67% of smaller sized geothermal power plants

On a macro level, the Government of Indonesia committed to reduce its carbon dioxide emissions by 26% by 2020 at the 2009 United Nations Climate Change Conference in Copenhagen and during 2015 in Paris.

East Africa

In East Africa the geothermal potential along the Rift Valley is estimated at several thousand MW. The different countries along the Rift Valley are at different stages of development of their respective geothermal potentials.

In **Kenya**, there are already several geothermal power plants, including the only geothermal IPP in Africa, our Olkaria III complex. The Government of Kenya has identified the country's untapped geothermal potential as the most suitable indigenous source of electricity and it aspires to reach 5,000 MW of geothermal power by 2030. To attain such number, GDC was formed to fast track the development of geothermal resources in Kenya. Ormat has as a 51% interest in a consortium that signed a PPA for a 35 MW geothermal power plant in the Menengai area.

The Government of Kenya is aiming to reach 22.7GW of power generating capacity by 2033, under the Least-Cost Power Development Plan 2013-33 with a target of 42% of such capacity generated from renewable energy sources (including large hydro but excluding solar).

In December 2012, FITs for various technologies were reviewed and the process of negotiating PPAs streamlined. Projects under this mechanism have priority grid access at the cost of the developer. Geothermal projects from 35 MW to 70 MW have a USD $0.088 per kWh (up to 500MW) FIT.

In 2015, the Departmental Committee of Finance, Planning, and Trade (DCFPT) amended the Income Tax Act in view of the 2015 Finance Bill. The amendments include maintaining the enhanced investment deduction of 150% under section 17B and extending the period of deduction of tax losses to over 10 years.

The governments of **Djibouti, Ethiopia, Eretria, Tanzania, Uganda, Rwanda** and **Zambia** are exploring ways to develop geothermal in their countries, mostly through the help of international development organizations such as the World Bank.

In January 2014, energy ministers and delegates from 19 countries committed to the creation of the Africa Clean Energy Corridor Initiative (Corridor), at a meeting in Abu Dhabi convened by the International Renewable Energy Agency (IRENA). The Corridor will boost the deployment of renewable energy and aim to help meet Africa’s rising energy demand with clean, indigenous, cost-effective power from sources including hydro, geothermal, biomass, wind and solar.

East Africa and South East Asia may benefit from two initiatives announced by President Obama. In June 2013, the Power Africa initiative was announced, which contemplated that the U.S. would invest up to $7.0 billion in sub-Saharan Africa over the ensuing five years with the aim of doubling access to power. The program will partner the U.S. government with the governments of six sub-Saharan countries, among them Kenya, Ethiopia and Tanzania, that have the potential for geothermal energy development. In 2012, President Obama proposed the U.S. Asia Pacific Comprehensive Energy Partnership (USACEP) that encourages U.S. companies to develop renewable energy in South East Asian countries, including Indonesia. The U.S. will provide up to $6.0 billion to support the Partnership.

Other opportunities

Recovered Energy Generation

In addition to our geothermal power generation activities, we are pursuing recovered energy-based power generation opportunities in North America and the rest of the world. We believe recovered energy-based power generation will ultimately benefit from the efforts to reduce greenhouse gas emissions. For example, in the U.S., FERC has expressed its position that one of the goals of new natural gas pipeline design should be to facilitate the efficient, low-cost transportation of fuel through the use of waste heat (recovered energy) from combustion turbines or reciprocating engines that drive station compressors to generate electricity for use at compressor stations or for commercial sale. FERC has, as a matter of policy, requested natural gas pipeline operators filing for a certificate of approval for new pipeline construction or expansion projects to examine “opportunities to enhance efficiencies for any energy consumption processes in the development and operation” of the new pipeline. We have built over 21 power plants which generate electricity from “waste heat” from gas turbine-driven compressor stations along interstate natural gas pipelines, from midstream gas processing facilities, and from processing industries in general.

Several states, and to a certain extent, the federal government, have recognized the environmental benefits of recovered energy-based power generation. For example, 15 states currently allow electric utilities to include recovered energy-based power generation in calculating such utilities' compliance with their mandatory or voluntary RPS and/or Energy Efficient Resources Standards. In addition, California modified the Self Generation Incentive Program (SGIP), which allows recovered energy-based generation to qualify for a per watt incentive.

In 2012, the Governor of Utah signed into law SB12 that enables the sale of electricity directly to large energy users. This direct purchase and sale, could create a market opportunity for our REG technology in Utah. The local utility has developed a tariff to provide rates and methodologies for companies that want to buy power directly from renewable generation facilities.

Also in 2012, Senate Bill 315 was enacted by the State of Ohio. Senate Bill 315 made waste energy recovery eligible as a renewable resource for purposes of meeting the state’s Renewable Portfolio Standard, as well as an efficiency measure under the state’s Energy Efficiency Resource Standard.

In addition, in Colorado the state PUC ruled that Xcel Energy, the largest utility in Colorado, will begin offering a $500 per kW incentive for recycled energy projects. The incentive will be paid out over 10 years to developers and manufacturers who convert waste heat from stacks and process it into electricity.

At the Federal level, Under the Clean Power Plan, waste-heat-to-power (recovered energy) is an eligible technology that can be implemented by states as means to comply with their Clean Power Plan emissions reduction targets. The inclusion of waste-heat-to-power as an eligible technology under the Clean Power Plan will potentially create demand for REG in states that have good waste-heat resources, but that so far had no policies in place, like an RPS, to create demand for renewables.

Recovery of waste heat is also considered “environmentally friendly” in the western Canadian provinces. On November 22, 2015, the Government of Alberta released the Clean Leadership Plan that includes (a) phasing out of coal-fired electricity generation by 2030; (b) a commitment to generate 30 percent of Alberta’s electricity from renewable sources by 2030; (c) new financing for energy efficiency; and (d) an economy-wide price on carbon pollution. This comprehensive set of climate policies, once fully implemented, will encourage the development of renewable energy technologies, including waste heat recovering, in Alberta. We believe that Europe and other markets worldwide may offer similar opportunities in recovered energy-based power generation.

In summary, the market for the recovery of waste heat converted into electricity exists either when the already available electricity is expensive or where the regulatory environment facilitates construction and marketing of power generated from recovered waste heat. However, such projects tend to be relatively small (up to 6MW) and we expect the growth to be relatively slow and geographically scattered.

New activities under our strategic plan

The traditional grid is undergoing a major disruption. The continued decline in Solar PV prices is impacting renewable energy pricing and the growth in intermittent green energy is generating increasing strains on the grid, mainly in the U.S and Europe. As a result, electricity storage is becoming a key component of the future grid. In parallel, we see movement of C&I and communities toward direct purchases of electricity.

Energy Storage

Energy storage systems utilize low cost, surplus, available electricity that enables utilities to optimize the operation of the grid and generators to run closer to full capacity for longer periods of time and operate more efficiently and effectively. With the increasing use of wind and solar energy, the need for storage services such as balancing services, frequency regulation, rapid generation ramping and movement of energy from times of excess to times of high demand is becoming more important.

The global energy storage market is still developing, with specific applications and geographies leading the overall market. Based on Navigant research, approximately 80 GW of energy storage is forecasted to be installed through 2024, representing accumulated installed revenues for this period of up to $68 billion (compound annual growth rate of 36.9%). We refer to the Navigant research as a possible reference point, but we do not necessarily concur with its estimate.

We see the storage market evolving in a manner like the broader renewable energy market, with developers diversifying their offerings to include storage projects at C&I and grid scale sites. Storage technology involves multiple components from storage devices, software and electrical components for communication systems and grid interconnection equipment. Some of the capabilities required are similar to the development of renewable energy power plants and include the ability to sell projects or services to similar entities with which we have already created sustainable relationships.

Ormat plans to enter the energy storage market in one or more ways, such as project developer, integrator, EPC and equity investor and owner. We expect that our global presence, experience in technology integration, and flexible business models, and our reputation and experience in the geothermal and recovered energy sectors will help us expand into this growing sector.

C&I

The C&I sector is shifting from centralized electricity generation systems to distributed resources supported by emerging models of direct PPAs with renewable power plants, on-site deployments, and customized solutions to energy management. Participants in the C&I sector are motivated to purchase renewable energy to reduce costs and diversify their energy supply, to lock in long-term energy price stability and carbon footprint reductions, to achieve renewable energy targets and to demonstrate leadership, innovation, and competitive first mover advantages. Ormat sees C&I customers as a natural expansion of our customer base from regulated utilities to medium and large C&I clients desiring to contract for renewable energy.

The advances in electricity storage technology together with high period demand charges, demand response programs, concern over electricity supply reliability and more aggressive goals for renewable energy content than those of centralized electricity suppliers are all factors that have supported the growth of the C&I market. The need for technical customized solutions to meet these varied C&I needs fits well with our experience in providing customized geothermal and REG solutions to various customers around the world.

Ormat's capabilities as an integrator, solution provider and product packager should help us to compete in the market place.

Solar PV

The market for Solar PV power grew significantly in recent years, driven by a combination of favorable government policies and a decline in equipment prices. We are monitoring market drivers with the potential to develop Solar PV power plants in locations where we can offer competitively priced power generation. Our focus currently is on large-scale solar power plant development opportunities worldwide such as in: (i) Chile, where the total installed Solar PV capacity increased from 6 MW in 2013 to almost 1 GW by the end of 2015 and is currently considered the cheapest source of electricity in the country, (ii) Mexico, considered among the largest potential national markets in Latin America on the strength of high solar resources and recent energy market reform, (iii) India, where the central government recently gave its approval to ramp up India's solar power capacity target to achieve 100 GW by 2022 (60 GW of grid connected solar power projects and 40 GW of rooftop solar) and (iv) the East Africa region, where a considerable amount of solar radiation and abundant available land constitute significant solar potential. Governments in the East Africa region have introduced various solar targets and incentives which provide opportunities for installing grid-tied and off-grid Solar PV systems to displace fuel costs.

Competitive Strengths

Competitive Assets. We believe our assets are competitive for the following reasons:

- *Contracted Generation.* All of the electricity generated by our geothermal power plants is currently sold pursuant to long-term PPAs with an average remaining life of approximately 15 years.

- *Baseload Generation*. All of our geothermal power plants supply all or a part of the baseload capacity of the electric system in their respective markets. This means they supply electric power on an around-the-clock basis. This provides us with a competitive advantage over other renewable energy sources, such as wind power, solar power or hydro-electric power (to the extent they depend on precipitation), which cannot provide baseload capacity because of their intermittent nature.

- *Ancillary Services.* Geothermal power plants positively impact electrical grid stability and provide valuable ancillary services. Because of the baseload nature of their output, they have high transmission utilization efficiency, provide capacity, provide grid inertia and reduce the need for ancillary services such as voltage regulation, reserves and flexible capacity. Other intermittent renewables create integration costs, adding a significant value for geothermal energy.

Competitive Pricing. Geothermal power plants, while site specific, are economically feasible in many locations, and the electricity they generate is generally price competitive under existing economic conditions and existing tax and regulatory regimes compared to electricity generated from fossil fuels or other renewable sources in many places around the world. Geothermal energy is recognized as one of the lower cost sources of energy from a levelized cost of energy (LCOE) perspective.

Ability to Finance Our Activities from Internally Generated Cash Flow. The cash flow generated by our portfolio of operating geothermal and REG power plants provides us with a robust and predictable base for certain exploration, development, and construction activities. We plan to evaluate various alternatives for financing the expansion of our business as we further develop and implement our new strategic plan.

Growing Legislative Demand for Environmentally-Friendly Renewable Resource Assets. Most of our currently operating power plants produce electricity from geothermal energy sources. The clean and sustainable characteristics of geothermal energy give us a competitive advantage over fossil fuel-based electricity generation as countries increasingly seek to balance environmental concerns with demands for reliable sources of electricity.

High Efficiency from Vertical Integration. Unlike our competitors in the geothermal industry, we are a fully-integrated geothermal equipment, services, and power provider. We design, develop, and manufacture equipment that we use in our geothermal and REG power plants. Our intimate knowledge of the equipment that we use in our operations allows us to operate and maintain our power plants efficiently and to respond to operational issues in a timely and cost-efficient manner. Moreover, given the efficient communications among our subsidiary that designs and manufactures the products we use in our operations and our subsidiaries that own and operate our power plants, we are able to quickly and cost effectively identify and repair mechanical issues and to have technical assistance and replacement parts available to us as and when needed.

Exploration and Drilling Capabilities. We have in-house capabilities to explore and develop geothermal resources and have established a drilling operation that currently owns nine drilling rigs. We employ an experienced resource group that includes engineers, geologists, and drillers, which executes our exploration and drilling plans for projects that we develop.

Highly Experienced Management Team. We have a highly qualified senior management team with extensive experience in the geothermal power sector.

Technological Innovation. We have 72 U.S. patents in force (and have approximately 30 U.S. patents pending) relating to various processes and renewable resource technologies. All of our patents are internally developed. Our ability to draw upon internal resources from various disciplines related to the geothermal power sector, such as geological expertise relating to reservoir management, and equipment engineering relating to power units, allows us to be innovative in creating new technologies and technological solutions.

Limited Exposure to Fuel Price Risk. A geothermal power plant does not need to purchase fuel (such as coal, natural gas, or fuel oil) in order to generate electricity. Thus, once the geothermal reservoir has been identified and estimated to be sufficient for use in a geothermal power plant, the drilling of wells is complete and the plant has a PPA, the plant is not exposed to fuel price or fuel delivery risk apart from the impact fuel prices may have on the price at which we sell power under PPAs that are based on the relevant power purchaser’s avoided costs.

Although we are confident in our competitive position in light of the strengths described above, we face various challenges in the course of our business operations, including as a result of the risks described in Item 1A — “Risk Factors” below, the trends and uncertainties discussed in “Trends and Uncertainties” under Item 7 — “Management’s Discussion and Analysis of Financial Condition and Results of Operations” below, and the competition we face in our different business segments described under “Competition” below.

Business Strategy

Our strategy is to continue building a geographically balanced portfolio of geothermal and recovered energy assets, and to continue to be a leader in the geothermal energy market with the objective of becoming a leading global provider of renewable energy. During 2015, we have refined and started to implement a number of the elements of a new multi-year strategic plan. We expect the plan to evolve over time in response to market conditions and other factors. We intend to implement this strategy through:

- *Development and Construction of New Geothermal Power Plants* — continuously seeking out commercially exploitable geothermal resources, developing and constructing new geothermal power plants and entering into long-term PPAs providing stable cash flows in jurisdictions where the regulatory, tax and business environments encourage or provide incentives for such development;

- *Expanding our geographical reach* – increasing our business development activities in an effort to grow our business in the global markets in both business segments. While we continue to evaluate global opportunities, we currently see Mexico, Chile, Indonesia and Ethiopia as very attractive markets for us. We are actively looking at ways to expand our presence in those countries.

- *Acquisition of New Assets* — expanding and accelerating growth through acquisition activities globally, aiming to acquire from third parties additional geothermal and Solar PV assets as well as companies that will expedite our entrance into the storage and C&I markets;

- *Manufacturing and Providing Products and EPC Services Related to Renewable Energy* — designing, manufacturing and contracting power plants for our own use and selling to third parties power units and other generation equipment for geothermal and recovered energy-based electricity generation;

- *Expanding into New Technologies* – leveraging our technological capabilities over a variety of renewable energy platforms, including solar power generation and energy storage. Initially, however, we expect that our focus will be on expanding our core geothermal competencies, such as expanding into more high temperature geothermal generation equipment and facilities. For example, we recently announced a new collaboration with Toshiba described below, which we anticipate may facilitate joint development of geothermal systems consisting of Ormat's binary system and Toshiba's flash system, among other things. We may acquire companies with integration and technological capabilities we do not currently have, or develop new technology ourselves, where we can effectively leverage our expertise to implement this part of our strategic plan.

- *Expand our customer base* - evaluating a number of strategies for expanding our customer base to the C&I market. In the near term, however, we expect that a majority of our revenues will continue to be generated as they now are, with our traditional electrical utility customer base for the Electricity segment.

- *Increasing Output from Our Existing Power Plants* — increasing output from our existing geothermal power plants by adding additional generating capacity, upgrading plant technology, and improving geothermal reservoir operations, including improving methods of heat source supply and delivery;

- *Cost saving by increasing efficiencies* – increasing efficiencies in our operating power plants and manufacturing facility including procurement by adding new technologies, restructuring of management control, automating part of our manufacturing work and centralizing our operating power plants.

- *Technological Expertise* — investing in research and development of renewable energy technologies and leveraging our technological expertise to continuously improve power plant components, reduce operations and maintenance costs, develop competitive and environmentally friendly products for electricity generation and target new service opportunities.

Recent Developments

The most significant recent developments in our company and business are described below.

On February 3, 2016, we announced that we commenced commercial operation of Plant 4 in the Olkaria III complex in Kenya, increasing the complex total generating capacity by 29 MW to 139 MW. Plant 4 will sell its electricity to KPLC under a 20-year PPA. In October 2015, Ormat signed an amendment to the PPA with KPLC that enables the increase of the capacity of Plant 4 expansions to an aggregate of 100 MW, in phases. Plant 4 was financed by Ormat equity which is covered by an insurance policy from MIGA (a member of the World Bank Group) to cover Ormat's exposure to certain political risks involved in operating in developing countries.

On January 12, 2016, we announced that we commenced construction of the 35 MW Platanares geothermal project in Honduras. In 2013, Ormat signed a BOT contract for the Geotérmica Platanares geothermal project in Honduras with ELCOSA, a privately owned Honduran energy company, for approximately 15 years from the COD. The Platanares project will sell its power, mainly under 30-year PPA with the national utility of Honduras, ENEE. We expect the project to reach commercial operation by the end of 2017 and generate average annual revenues of approximately $33 million.

On December 7, 2015, we announced that we signed a binding MOU to acquire, gradually, 85% of Geothermie Bouillante SA (GB) at a total company enterprise value of up to approximately €52 million (approximately USD$56 million, based on current foreign currency exchange rates). GB owns and operates a 14.75 MW geothermal power plant and owns two exploration licenses with a total additional potential capacity of up to 30 MW, all located on Guadeloupe Island, a French territory in the Caribbean. Upon closing, Ormat will hold approximately 80% of GB which will be increased to 85% within two years by capital investment agreed upon in the MOU.

Ormat's total consideration will be paid in installments in accordance with specific milestones, including production milestones, expected to be achieved in the next few years. Closing is expected by May 2016 and the transaction is expected to be immediately accretive to Ormat's earnings per share.

GB has two PPAs with Électricité de France S.A. (EDF) the French electric utility. A new 15-year PPA with EDF with improved energy rates recently became effective and replaced the previous PPAs.

On November 17, 2015, we announced that Mr. Yoram Bronicki resigned from his position as the Chairman of our Board of Directors, effective November 16, 2015. Upon the recommendation of the Nominating and Governance Committee, the Board appointed Mr. Stanley Stern as a director to fill the vacancy on the Board, and appointed existing director Mr. Gillon Beck as the Chairman of the Board. Mr. Beck also served as our Chairman from May 2012 until June 2014.

On November 15, 2015, Ms. Dita Bronicki resigned from her position as a director on our Board of Directors and as a member of the Compensation Committee. Upon the recommendation of the Nominating and Governance Committee, the Board appointed Ms. Ravit Barniv as a director to fill the vacancy on the Board and as a member of the Compensation Committee.

On October 14, 2015, we announced that we signed a strategic collaboration agreement with Toshiba Corporation to develop strategic opportunities for collaboration in the areas of geothermal power generation systems and related equipment. Under the terms of the agreement, Ormat and Toshiba will explore and develop strategic opportunities that will enable them to offer potential customers a more competitive solution for comprehensive supplies and services related to geothermal development, from resource assessment, field development and power plant EPC to power plant operation.

On September 17, 2015, the Don A. Campbell phase 2 geothermal power plant located in Mineral County, Nevada began commercial operation 10 months after the project broke ground and less than two years after we commenced firm operation of the first phase in December 2013. The phase 2 power plant is generating approximately 20 MW (net) and we sell this electricity under a 20-year PPA with SCPPA. SCPPA resells the entire output of this plant to the Los Angeles Department of Water and Power (LADWP).

On September 11, 2015, Kenya's Income Tax Act was amended pursuant to certain provisions of the recently adopted Finance Act, 2015. Among other matters, these amendments retain the enhanced investment deduction of 150% under Section 17B of the Income Tax Act, extend the period for deduction of tax losses from five years to ten years under Sections 15(4) and 15(5) of the Income Tax Act, and amend the effective date from January 1, 2016 to January 1, 2015 under Sections 15(4) and 15(5) of the Income Tax Act. Previously, we had a valuation allowance for the additional 50% investment deduction reducing our deferred tax asset in Kenya as the utilization of the related tax losses was not probable within the original five year carryforward period. As a result of the change in legislation and the expected continued profitability during the extended carryforward period, we expect that we will be able to fully utilize the carryforward tax losses within the ten year period and as such we released the valuation allowance in Kenya resulting in a $49.4 million tax benefit in the year ended December 31, 2015.

On July 31, 2015, one of our indirect wholly-owned subsidiaries, Ortitlàn, Limitada, obtained a 12-year secured term loan in the principal amount of $42.0 million for the 20 MW Amatitlàn power plant in Guatemala. Under the credit agreement with Banco Industrial S.A. and Westrust Bank (International) Limited, we have the flexibility to expand the Amatitlàn power plant with financing to be provided either via equity, additional debt from Banco Industrial S.A. or from other lenders, subject to certain limitations on expansion financing in the credit agreement.

On June 8, 2015, we repurchased $30.6 million aggregate principal amount of our OFC Senior Secured Notes from certain OFC noteholders. As a result of the repurchase, we recognized a loss of $1.7 million, including amortization of deferred financing cost of $0.5 million, which is included in other non-operating income (expense), net in the consolidated statements of operations and comprehensive income for the year ended December 31, 2015.

On May 7, 2015, we announced that we were selected through a competitive bid process and signed a $98.8 million EPC contract for a geothermal project in Chile. Under the terms of the EPC contract we will provide two air-cooled OECs for a high enthalpy reservoir. The project is scheduled to be completed by mid-2017.

On April 30, 2015, we announced the closing of an equity transaction with Northleaf Geothermal Holdings, LLC (Northleaf). Pursuant to the purchase agreement, which the parties executed on February 5, 2015, Northleaf acquired a 36.75% equity interest in ORPD for a purchase price of $162.3 million. The joint venture includes Ormat's Puna geothermal power plant in Hawaii, the Don A. Campbell geothermal power plant in Nevada, and nine power plant units across three recovered energy generation assets known as OREG 1, OREG 2, and OREG 3. The purchase price implies an aggregate equity value for the portfolio of approximately $442.0 million. The actual purchase price and the percentage interest acquired by Northleaf were adjusted based on the Canadian Dollar/US Dollar exchange rate and was affected by the devaluation of the Canadian Dollar.

On March 24, 2015, we announced that we entered into a 20-year PPA with SCPPA for interstate delivery of electricity from the Don A. Campbell phase 2 power plant in Mineral County, Nevada. Under the terms of the PPA, the Don A. Campbell phase 2 power plant will receive a rate of $81.25 per MWh with no annual escalation. The power plant began commercial operation on September 17, 2015. Northleaf Capital Partners, Ormat's new joint venture investor, will purchase an approximately 36.75% interest in the project which will be added to the existing ORPD projects portfolio once the project is completed and commissioned.

On February 12, 2015, we announced the completion of the share exchange transaction with Ormat Industries, our then-parent company, in which we acquired Ormat Industries through the issuance of 30,203,186 new shares of our common stock to Ormat Industries' shareholders in exchange for all of the outstanding ordinary shares of Ormat Industries, reflecting an exchange ratio of 0.2592 shares of our common stock for each ordinary share of Ormat Industries. One of the key consequences of this transaction was that the number of shares of our common stock held by non-affiliated, “public” shareholders was increased from approximately 40% to approximately 76% of our total shares outstanding, which we believe should help elevate trading volume and may increase equity coverage.

As previously disclosed, we entered into several agreements in connection with the share exchange, including the following:

Voting agreements with the then principal shareholders of Ormat Industries, FIMI ENRG, Limited Partnership and FIMI ENRG, L.P. (together FIMI) and Bronicki Investments Ltd. (Bronicki), which currently beneficially own approximately 14.91% and 7.76% of our outstanding shares, respectively. Under these voting agreements, FIMI and Bronicki agreed, among other things, to comply in all respects with the Israeli Tax Ruling applicable to the Ormat Industries shareholders.

Voting neutralization agreements with FIMI and Bronicki, whereby FIMI and Bronicki agreed, among other things, to certain restrictions on their shares of our common stock. Among other things, these voting neutralization agreements:

o require these shareholders to vote all voting securities owned by FIMI and Bronicki and their respective affiliates in excess of 16% and 9%, respectively, of the combined voting power of our shares in proportion to votes cast by the other holders of our voting securities at any time any action is to be taken by our stockholders

o prohibit the acquisition of our voting securities by FIMI and Bronicki and their respective affiliates if after giving effect to any such acquisition FIMI and Bronicki and their respective affiliates would beneficially own voting securities representing in the aggregate more than 20% and 12%, respectively, of the combined voting power of our shares

o prohibit, prior to January 1, 2017 and subject to certain exceptions, the sale of more than 10% of our voting securities owned in the aggregate by FIMI and Bronicki

o allow, following January 1, 2017, the sale of our voting securities owned by FIMI and Bronicki only if they are not acting in concert to sell or, if they are, only with 20 days’ prior written notice to us, subject to certain exceptions for public sales and mergers and acquisitions transactions; and

o

prohibit FIMI and Bronicki from renewing their shareholder rights agreement beyond its current expiration date of May 22, 2017.

A registration rights agreement whereby FIMI and Bronicki may, subject to certain limitations, require us to prepare and file with the SEC a registration statement to register a public offering of the shares of our common stock held by them, on customary terms and conditions set forth in the agreement.

On February 5, 2015, the Tel Aviv Stock Exchange (the TASE) approved the listing of our common stock on the TASE beginning on February 10, 2015 and our common stock is now listed on both the NYSE and the TASE. We are still subject to the rules and regulations of the NYSE and of the SEC. Under the local regime for dual listing, U.S. listed companies, such as us, can dual-list on the TASE without additional regulatory requirements, using the same periodic reports, financial and other relevant disclosure information that they submit to the SEC and NYSE. However, as a result of the local regime requirements, we have undertaken, as part of the TASE listing, not to issue preferred stock for as long as our shares of common stock are listed on the TASE.

On February 4, 2015, we announced that the second phase of the McGinness Hills geothermal power plant located in Lander County, Nevada began commercial operation. Since February 1, 2015, the complex sells electricity under an amended PPA with NV Energy at a new energy rate of $85.58 per MWh with one percent annual escalator through December 2032. Following resource confirmation and excellent performance of the first phase of McGinness Hills, which had been operational since June 2012, the second phase initiated construction in March 2014. The second phase of the McGinness Hills plant came on line on February 1, 2015.

Operations of our Electricity Segment

How We Own Our Power Plants. We customarily establish a separate subsidiary to own interests in each power plant. Our purpose in establishing a separate subsidiary for each plant is to ensure that the plant, and the revenues generated by it, will be the only source for repaying indebtedness, if any, incurred to finance the construction or the acquisition (or to refinance the construction or acquisition) of the relevant plant. If we do not own all of the interest in a power plant, we enter into a shareholders agreement or a partnership agreement that governs the management of the specific subsidiary and our relationship with our partner in connection with the specific power plant. Our ability to transfer or sell our interest in certain power plants may be restricted by certain purchase options or rights of first refusal in favor of our power plant partners or the power plant's power purchasers and/or certain change of control and assignment restrictions in the underlying power plant and financing documents. All of our domestic geothermal and REG power plants, with the exception of the Puna complex, which is an Exempt Wholesale Generator, are Qualifying Facilities under the PURPA, and are eligible for regulatory exemptions from most provisions of the FPA and certain state laws and regulations.

How We Explore and Evaluate Geothermal Resources. Since 2006, we have expanded our exploration activities, initially in the U.S. and more recently with an increasing focus internationally. It normally takes two to three years from the time we start active exploration of a particular geothermal resource to the time we have an operating production well, assuming we conclude the resource is commercially viable and determine to pursue its development. Exploration activities generally involve the phases described below.

Initial Evaluation. Identifying and evaluating potential geothermal resources by sampling and studying new areas combined with information available from public and private sources. We generally adhere to the following process, although our process can vary from site to site depending on geological circumstances and prior evaluation:

- We evaluate historic, geologic and geothermal information available from public and private databases, including geothermal, mining, petroleum and academic sources.

- We visit sites, sampling fluids for chemistry if necessary, to evaluate geologic conditions.

- We evaluate available data, and rank prospects in a database according to estimated size and perceived risk. For example, pre-drilled sites with extensive data are considered lower risk than “green field” sites. Both prospect types are considered critical for Ormat’s continued growth.

- We generally create a digital, spatial geographic information systems (GIS) database and 3D geologic model containing all pertinent information, including thermal water temperature gradients derived from historic drilling, geologic mapping information (e.g., formations, structure, alteration, and topography), and any available archival information about the geophysical properties of the potential resource.

- We assess other relevant information, such as infrastructure (e.g., roads and electric transmission lines), natural features (e.g., springs and lakes), and man-made features (e.g., old mines and wells).

Our initial evaluation is usually conducted by our own staff, although we might engage outside service providers for some tasks from time to time. The costs associated with an initial evaluation vary from site to site, based on various factors, including the acreage involved and the costs, if any, of obtaining information from private databases or other sources. On average, our expenses for an initial evaluation range from approximately $10,000 to $50,000 including travel, chemical analyses, and data acquisition.

If we conclude, based on the information considered in the initial evaluation, that the geothermal resource could support a commercially viable power plant, taking into account various factors described below, we proceed to land rights acquisition.

Land Acquisition. Acquiring land rights to any geothermal resources our initial evaluation indicates could potentially support a commercially viable power plant, taking into account various factors. For domestic power plants, we either lease or own the sites on which our power plants are located. For our foreign power plants, our lease rights for the plant site are generally contained in the terms of a concession agreement or other contract with the host government or an agency thereof. In certain cases, we also enter into one or more geothermal resource leases (or subleases) or a concession or an option agreement or other agreement granting us the exclusive right to extract geothermal resources from specified areas of land, with the owners (or sublessors) of such land. In some cases we obtain first the exploration license and once certain investment requirements are met, we can obtain the exploitation rights. This usually gives us the right to explore, develop, operate, and maintain the geothermal field, including, among other things, the right to drill wells (and if there are existing wells in the area, to alter them) and build pipelines for transmitting geothermal fluid. In certain cases, the holder of rights in the geothermal resource is a governmental entity and in other cases a private entity. Usually the duration of the lease (or sublease) and concession agreement corresponds to the duration of the relevant PPA, if any. In certain other cases, we own the land where the geothermal resource is located, in which case there are no restrictions on its utilization. Leasehold interests in federal land in the U.S. are regulated by the BLM and the Minerals Management Service. These agencies have rules governing the geothermal leasing process as discussed above under “Description of Our Leases and Lands”.

For most of our current exploration sites in the U.S., we acquire rights to use geothermal resource through land leases with the BLM, with various states, or through private leases. Under these leases, we typically pay an up-front non-refundable bonus payment, which is a component of the competitive lease process. In addition, we undertake to pay nominal, fixed annual rent payments for the period from the commencement of the lease through the completion of construction. Upon the commencement of power generation, we begin to pay to the lessors long-term royalty payments based on the use of the geothermal resources as defined in the respective agreements. These payments are contingent on the power plant’s revenues. A summary of our typical lease terms is provided below under “Description of our Leases and Lands”.

The up-front bonus and royalty payments vary from site to site and are based, among other things, on current market conditions.

Surveys. Conducting geological, geochemical, and/or geophysical surveys on the sites acquired. Following the acquisition of land rights for a potential geothermal resource, we conduct additional surface water analyses, soil surveys, and geologic mapping to determine proximity to possible heat flow anomalies and up-flow/permeable zones. We augment our digital database with the results of those analyses and create conceptual and digital geologic models to describe geothermal system controls. We then initiate a suite of geophysical surveys (e.g., gravity, magnetics, resistivity, magnetotellurics, reflection seismic, LiDAR, and spectral surveys) to assess surface and sub-surface structure (e.g., faults and fractures) and improve the geologic model of fluid-flow conduits and permeability controls. All pertinent geological and geophysical data are used to create three-dimensional geologic models to identify drill locations. These surveys are conducted incrementally considering relative impact and cost, and the geologic model is updated continuously.

We make a further determination of the commercial viability of the geothermal resource based on the results of this process, particularly the results of the geochemical surveys estimating temperature and the overall geologic model, including potential resource size. If the results from the geochemical surveys are poor (i.e., low derived resource temperatures or poor permeability) or the geologic model indicates small or deep resource, we re-evaluate the commercial viability of the geothermal resource and may not proceed to exploratory drilling. We generally only move forward with those sites that we believe have a high probability for development.

Exploratory Drilling. Drilling one or more exploratory wells on the high priority, relatively low risk sites to confirm and/or define the geothermal resource. If we proceed to exploratory drilling, we generally use outside contractors to create access roads to drilling sites and related activities. We have continued efforts to reduce exploration costs and therefore, after obtaining drilling permits, we generally drill temperature gradient holes and/or core holes that are lower cost than slim holes (used in the past) using either our own drilling equipment, whenever possible, or outside contractors. If the obtained data supports a conclusion that the geothermal resource can support a commercially viable power plant, it will be used as an observation well to monitor and define the geothermal resource. If the core hole indicates low temperatures or does not support the geologic model of anticipated permeability, it may be plugged and the area reclaimed. In undrilled sites, we typically step up from shallow (500-1000 ft) to deeper (2000-4000 ft) wells as confidence improves. Following proven temperature in core wells, we typically move to slim and/or full size wells to quantify permeability.

Each year we determine and approve an exploration budget for the entire exploration activity in such year. We prioritize budget allocation between the various geothermal sites based on commercial and geological factors. The costs we incur for exploratory drilling vary from site to site based on various factors, including the accessibility of the drill site, the geology of the site, and the depth of the resource. However, on average, exploration costs, prior to drilling of a full-size well are approximately $1.0 million to $3.0 million for each site, not including land acquisition. However, we only reach such spending levels for sites that proved to be successful in the early stages of the exploration.

At various points during our exploration activities, we re-assess whether the geothermal resource involved will support a commercially viable power plant based on information available at that time. Among other things, we consider the following factors:

- New data and interpretations obtained concerning the geothermal resource as our exploration activities proceed, and particularly the expected MW capacity power plant the resource can be expected to support. The MW capacity can be estimated using analogous systems and/or quantitative heat in place estimates until results from drilling and flow tests quantify temperature, permeability, and resulting resource size.
- Current and expected market conditions and rates for contracted and merchant electric power in the market(s) to be serviced.
- Availability of transmission capacity.
- Anticipated costs associated with further exploration activities and the relative risk of failure.
- Anticipated costs for design and construction of a power plant at the site.
- Anticipated costs for operation of a power plant at the site, particularly taking into account the ability to share certain types of costs (such as control rooms) with one or more other power plants that are, or are expected to be, operating near the site.

If we conclude that the geothermal resource involved will support a commercially viable power plant, we proceed to constructing a power plant at the site.

How We Construct Our Power Plants. The principal phases involved in constructing one of our geothermal power plants are as follows:

- Drilling production and injection wells.
- Designing the well field, power plant, equipment, controls, and transmission facilities.
- Obtaining any required permits, electrical interconnection and transmission agreements.

- Manufacturing (or in the case of equipment we do not manufacture ourselves, purchasing) the equipment required for the power plant.

- Assembling and constructing the well field, power plant, transmission facilities, and related facilities.

It generally takes approximately two years from the time we drill a production well, until the power plant becomes operational.

Drilling Production and Injection Wells. We consider completing the drilling of first production well as the beginning of our construction phase for a power plant. However, it is not always sufficient for a full release for construction. The number of production wells varies from plant to plant depending, among other things, on the geothermal resource, the projected capacity of the power plant, the power generation equipment to be used and the way geothermal fluids will be re-injected through injection wells to maintain the geothermal resource and surface conditions. We generally drill the wells ourselves although in some cases we use outside contractors.

The cost for each production and injection well varies depending, among other things, on the depth and size of the well and market conditions affecting the supply and demand for drilling equipment, labor and operators. Our typical cost for each production and injection well is approximately $4.0 million with a range of $1.0 million to $10.0 million.

Design. We use our own employees to design the well field and the power plant, including equipment that we manufacture and that will be needed for the power plant. The designs vary based on various factors, including local laws, required permits, the geothermal resource, the expected capacity of the power plant and the way geothermal fluids will be re-injected to maintain the geothermal resource and surface conditions.

Permits. We use our own employees and outside consultants to obtain any required permits and licenses for our power plants that are not already covered by the terms of our site leases. The permits and licenses required vary from site to site, and are described below under “Environmental Permits”.

Manufacturing. Generally, we manufacture most of the power generating unit equipment we use at our power plants. Multiple sources of supply are generally available for all other equipment we do not manufacture.

Construction. We use our own employees to manage the construction work. For site grading, civil, mechanical, and electrical work we use subcontractors.

During fiscal year 2015, in the Electricity segment, we focused on the commencement of operations at the McGinness Hills phase 2 and the Don A. Campbell phase 2 power plants. We continued with construction of the Olkaria III Plant 4. We began construction of the Don A. Campbell phase 2 power plant and the Olkaria III Plant 4 during fiscal year 2014. We began construction of the McGinness Hills phase 2 power plant during fiscal year 2013.

In January 2016, we released for construction the Platanares project in Honduras. We also started development activity in Tungsten and Dixie Meadows projects in Nevada.

When deciding whether to continue holding lease rights and/or to pursue exploration activity, we diligently prioritize our prospective investments, taking into account resource and probability assessments in order to make informed decisions about whether a particular project will support commercial operations. As a result, during fiscal year 2015, we discontinued exploration activities at ten future prospects, including Kona and Ulupalakua (Maui) in Hawaii, Warm Springs Tribe and Newberry - Twilight in Oregon, Whirlwind Valley in Utah, Argenta, Hycroft and South Jersey in Nevada and Mariman and Quinohuen in Chile.

During fiscal year 2014, we discontinued exploration and development activities at seven exploration sites and one development project, including Huu Dumpo in Indonesia, Mount Spurr in Alaska, San Pablo, San Jose II, and Aroma in Chile, Silver Lake, Summer Lake and Foley Hot Springs in Oregon and Wister in California.

During fiscal year 2013, we discontinued exploration and development activities at three sites, including Magic Reservoir in Idaho, Wildhorse (Mustang) in Nevada and Drum Mountain in Utah. After conducting exploratory studies at those sites, we concluded that the respective geothermal resources would not support commercial operations. Costs associated with exploration activities at these sites were expensed accordingly (see “Write-off of Unsuccessful Exploration Activities” under Item 7 — “Management’s Discussion and Analysis of Financial Condition and

Results of Operations”).

We added to our exploration activities ten, four and two sites during the years ended December 31, 2015, 2014 and 2013, respectively.

How We Operate and Maintain Our Power Plants. In the U.S. we usually employ our subsidiary, Ormat Nevada, to act as operator of our power plants pursuant to the terms of an operation and maintenance agreement. Operation and maintenance of our foreign projects are generally provided by our subsidiary that owns the relevant project. Our operations and maintenance practices are designed to minimize operating costs without compromising safety or environmental standards while maximizing plant flexibility and maintaining high reliability. Our operations and maintenance practices for geothermal power plants seek to preserve the sustainable characteristics of the geothermal resources we use to produce electricity and maintain steady-state operations within the constraints of those resources reflected in our relevant geologic and hydrologic studies. Our approach to plant management emphasizes the operational autonomy of our individual plant or complex managers and staff to identify and resolve operations and maintenance issues at their respective power plants; however each power plant or complex draws upon our available collective resources and experience, and that of our subsidiaries. We have organized our operations such that inventories, maintenance, backup, and other operational functions are pooled within each power plant complex and provided by one operation and maintenance provider. This approach enables us to realize cost savings and enhances our ability to meet our power plant availability goals.

Safety is a key area of concern to us. We believe that the most efficient and profitable performance of our power plants can only be accomplished within a safe working environment for our employees. Our compensation and incentive program includes safety as a factor in evaluating our employees, and we have a well-developed reporting system to track safety and environmental incidents, if any, at our power plants.

How We Sell Electricity. In the U.S., the purchasers of power from our power plants are typically investor-owned electric utility companies. Outside of the U.S., the purchaser is either a state-owned utility or a privately-owned entity and we typically operate our facilities pursuant to rights granted to us by a governmental agency pursuant to a concession agreement. In each case, we enter into long-term contracts (typically, PPAs) for the sale of electricity or the conversion of geothermal resources into electricity. Although previously a power plant's revenues under a PPA generally consisted of two payments — energy payments and capacity payments, our recent PPAs provide for energy payments only. Energy payments are normally based on a power plant's electrical output actually delivered to the purchaser measured in kilowatt hours, with payment rates either fixed or indexed to the power purchaser's "avoided" power costs (i.e., the costs the power purchaser would have incurred itself had it produced the power it is purchasing from third parties) or rates that escalate at a predetermined percentage each year. Capacity payments are normally calculated based on the generating capacity or the declared capacity of a power plant available for delivery to the purchaser, regardless of the amount of electrical output actually produced or delivered. In addition, most of our domestic power plants located in California are eligible for capacity bonus payments under the respective PPAs upon reaching certain levels of generation.

How We Finance Our Power Plants. Historically we have funded our power plants with a different sources of liquidity such as a combination of non-recourse or limited recourse debt, including lease financing, tax monetization transactions, internally generated cash, which includes funds from operation, as well as proceeds from loans under corporate credit facilities, sale of securities, and sale of membership interests. Such leveraged financing permits the development of power plants with a limited amount of equity contributions, but also increases the risk that a reduction in revenues could adversely affect a particular power plant's ability to meet its debt obligations. Leveraged financing also means that distributions of dividends or other distributions by plant subsidiaries to us are contingent on compliance with financial and other covenants contained in the financing documents.

Non-recourse debt or lease financing refers to debt or lease arrangements involving debt repayments or lease payments that are made solely from the power plant's revenues (rather than our revenues or revenues of any other power plant) and generally are secured by the power plant's physical assets, major contracts and agreements, cash accounts and, in many cases, our ownership interest in our affiliate that owns that power plant. These forms of financing are referred to as "project financing". Project financing transactions generally are structured so that all revenues of a power plant are deposited directly with a bank or other financial institution acting as escrow or security deposit agent. These funds are then payable in a specified order of priority set forth in the financing documents to ensure that, to the extent available, they are used to first pay operating expenses, senior debt service (including lease payments) and taxes, and to fund reserve accounts. Thereafter, subject to satisfying debt service coverage ratios and certain other conditions, available funds may be disbursed for management fees or dividends or, where there are subordinated lenders, to the payment of subordinated debt service.

In the event of a foreclosure after a default, our affiliate that owns the power plant would only retain an interest in the assets, if any, remaining after all debts and obligations have been paid in full. In addition, incurrence of debt by a power plant may reduce the liquidity of our equity interest in that power plant because the equity interest is typically subject both to a pledge in favor of the power plant's lenders securing the power plant's debt and to transfer and change of control restrictions set forth in the relevant financing agreements.

Limited recourse debt refers to project financing as described above with the addition of our agreement to undertake limited financial support for our affiliate that owns the power plant in the form of certain limited obligations and contingent liabilities. These obligations and contingent liabilities may take the form of guarantees of certain specified obligations, indemnities, capital infusions and agreements to pay certain debt service deficiencies. To the extent we become liable under such guarantees and other agreements in respect of a particular power plant, distributions received by us from other power plants and other sources of cash available to us may be required to be used to satisfy these obligations. Creditors of a project financing of a particular power plant may have direct recourse to us to the extent of these limited recourse obligations.

We have also used financing structures to monetize PTCs and other favorable tax benefits derived from the financed power plants and an operating lease arrangement for our Puna complex power plants.

We have recently used a sale of membership interests in two of our geothermal assets and nine of our REG facilities to fund corporate needs including funds for the construction of new projects. We may use such financing structure in the future.

How We Mitigate International Political Risk. We generally purchase insurance policies to cover our exposure to certain political risks involved in operating in developing countries, as described below under "Insurance". To date, our political risk insurance policies are with the Multilateral Investment Guaranty Agency (MIGA), a member of the World Bank Group, and Zurich Re, a private insurance and re-insurance company**.** Such insurance policies generally cover, subject to the limitations and restrictions contained therein, 80-90% of our losses resulting from a specified governmental act such as confiscation, expropriation, riots, the inability to convert local currency into hard currency, and, in certain cases, the breach of agreements. We have obtained such insurance for the Olkaria, Zunil and Sarulla projects.

Description of Our Leases and Lands

We have domestic leases on approximately 282,700 acres of federal, state, and private land in Alaska, California, Hawaii, Nevada, New Mexico and Oregon. The approximate breakdown between federal, state, private leases and owned land is as follows:

- 76% are leases with the U.S. government, acting through the BLM;
- 17% are leases with private landowners and/or leaseholders;
- 4% are leases with various states, none of which is currently material; and
- 3% are owned by us.

Each of the leases within each of the categories has standard terms and requirements, as summarized below. Internationally, our land position includes approximately 186,000 acres, most of which are geothermal exploration licenses for one prospect in Chile.

Bureau of Land Management (BLM) Geothermal Leases

Certain of our domestic project subsidiaries have entered into geothermal resources leases with the U.S. government, pursuant to which they have obtained the right to conduct their geothermal development and operations on federally-owned land. These leases are made pursuant to the Geothermal Steam Act and the lessor under such leases is the U.S. government, acting through the BLM.

BLM geothermal leases grant the geothermal lessee the right and privilege to drill for, extract, produce, remove, utilize, sell, and dispose of geothermal resources on certain lands, together with the right to build and maintain necessary improvements thereon. The actual ownership of the geothermal resources and other minerals beneath the land is retained in the federal mineral estate. The geothermal lease does not grant to the geothermal lessee the exclusive right to develop the lands, although the geothermal lessee does hold the exclusive right to develop geothermal resources within the lands. The geothermal lessee does not have the right to develop minerals unassociated with geothermal production and cannot prohibit others from developing the minerals present in the lands. The BLM may grant multiple leases for the same lands and, when this occurs, each lessee is under a duty to not unreasonably interfere with the development rights of the other. Because BLM leases do not grant to the geothermal lessee the exclusive right to use the surface of the land, BLM may grant rights to others for activities that do not unreasonably interfere with the geothermal lessee’s uses of the same land; such other activities may include recreational use, off-road vehicles, and/or wind or solar energy developments.

Certain BLM leases issued before August 8, 2005 include covenants that require the projects to conduct their operations under the lease in a workmanlike manner and in accordance with all applicable laws and BLM directives and to take all mitigating actions required by the BLM to protect the surface of and the environment surrounding the land. Additionally, certain leases contain additional requirements, some of which concern the mitigation or avoidance of disturbance of any antiquities, cultural values or threatened or endangered plants or animals, the payment of royalties for timber, and the imposition of certain restrictions on residential development on the leased land.

BLM leases entered into after August 8, 2005 require the geothermal lessee to conduct operations in a manner that minimizes impacts to the land, air, water, to cultural, biological, visual, and other resources, and to other land uses or users. The BLM may require the geothermal lessee to perform special studies or inventories under guidelines prepared by the BLM. The BLM reserves the right to continue existing leases and to authorize future uses upon or in the leased lands, including the approval of easements or rights-of-way. Prior to disturbing the surface of the leased lands, the geothermal lessee must contact the BLM to be apprised of procedures to be followed and modifications or reclamation measures that may be necessary. Subject to BLM approval, geothermal lessees may enter into unit agreements to cooperatively develop a geothermal resource. The BLM reserves the right to specify rates of development and to require the geothermal lessee to commit to a communalization or unitization agreement if a common geothermal resource is at risk of being overdeveloped.

Typical BLM leases issued to geothermal lessees before August 8, 2005 have a primary term of ten years and will renew so long as geothermal resources are being produced or utilized in commercial quantities, but cannot exceed a period of forty years after the end of the primary term. If at the end of the forty-year period geothermal steam is still being produced or utilized in commercial quantities and the lands are not needed for other purposes, the geothermal lessee will have a preferential right to renew the lease for a second forty-year term, under terms and conditions as the BLM deems appropriate.

BLM leases issued after August 8, 2005 have a primary term of ten years. If the geothermal lessee does not reach commercial production within the primary term, the BLM may grant two five-year extensions if the geothermal lessee: (i) satisfies certain minimum annual work requirements prescribed by the BLM for that lease, or (ii) makes minimum annual payments. Additionally, if the geothermal lessee is drilling a well for the purposes of commercial production, the primary term (as it may have been extended) may be extended for five years and as long thereafter as steam is being produced and used in commercial quantities (meaning the geothermal lessee either begins producing geothermal resources in commercial quantities or has a well capable of producing geothermal resources in commercial quantities and is making diligent efforts to utilize the resource) for thirty-five years. If, at the end of the extended thirty-five year term, geothermal steam is still being produced or utilized in commercial quantities and the lands are not needed for other purposes, the geothermal lessee will have a preferential right to renew the lease for fifty-five years, under terms and conditions as the BLM deems appropriate.

For BLM leases issued before August 8, 2005, the geothermal lessee is required to pay an annual rental fee (on a per acre basis), which escalates according to a schedule described therein, until production of geothermal steam in commercial quantities has commenced. After such production has commenced, the geothermal lessee is required to pay royalties (on a monthly basis) on the amount or value of (i) steam, (ii) by-products derived from production, and (iii) commercially de-mineralized water sold or utilized by the project (or reasonably susceptible to such sale or use).

For BLM leases issued after August 8, 2005, (i) a geothermal lessee who has obtained a lease through a non-competitive bidding process will pay an annual rental fee equal to $1.00 per acre for the first ten years and $5.00 per acre each year thereafter; and (ii) a geothermal lessee who has obtained a lease through a competitive process will pay a rental equal to $2.00 per acre for the first year, $3.00 per acre for the second through tenth year and $5.00 per acre each year thereafter. Rental fees paid before the first day of the year for which the rental is owed will be credited towards royalty payments for that year. For BLM leases issued, effective, or pending on August 5, 2005 or thereafter, royalty rates are fixed between 1.0-2.5% of the gross proceeds from the sale of electricity during the first ten years of production under the lease. The royalty rate set by the BLM for geothermal resources produced for the commercial generation of electricity but not sold in an arm’s length transaction is 1.75% for the first ten years of production and 3.5% thereafter. The royalty rate for geothermal resources sold by the geothermal lessee or an affiliate in an arm’s length transaction is 10.0% of the gross proceeds from the arm’s length sale. The BLM may readjust the rental or royalty rates at not less than twenty year intervals beginning thirty-five years after the date geothermal steam is produced.

In the event of a default under any BLM lease, or the failure to comply with any of the provisions of the Geothermal Steam Act or regulations issued under the Geothermal Steam Act or the terms or stipulations of the lease, the BLM may, 30 days after notice of default is provided to the relevant project, (i) suspend operations until the requested action is taken, or (ii) cancel the lease.

Private Geothermal Leases

Certain of our domestic project subsidiaries have entered into geothermal resources leases with private parties, pursuant to which they have obtained the right to conduct their geothermal development and operations on privately owned land. In many cases, the lessor under these private geothermal leases owns only the geothermal resource and not the surface of the land.

Typically, the leases grant our project subsidiaries the exclusive right and privilege to drill for, produce, extract, take and remove from the leased land water, brine, steam, steam power, minerals (other than oil), salts, chemicals, gases (other than gases associated with oil), and other products produced or extracted by such project subsidiary. The project subsidiaries are also granted certain non-exclusive rights pertaining to the construction and operation of plants, structures, and facilities on the leased land. Additionally, the project subsidiaries are granted the right to dispose geothermal fluid as well as the right to re-inject into the leased land water, brine, steam, and gases in a well or wells for the purpose of maintaining or restoring pressure in the productive zones beneath the leased land or other land in the vicinity. Because the private geothermal leases do not grant to the lessee the exclusive right to use the surface of the land, the lessor reserves the right to conduct other activities on the leased land in a manner that does not unreasonably interfere with the geothermal lessee’s uses of the same land, which other activities may include agricultural use (farming or grazing), recreational use and hunting, and/or wind or solar energy developments.

The leases provide for a term consisting of a primary term in the range of five to 30 years, depending on the lease, and so long thereafter as lease products are being produced or the project subsidiary is engaged in drilling, extraction, processing, or reworking operations on the leased land.

As consideration under most of our project subsidiaries' private leases, the project subsidiary must pay to the lessor a certain specified percentage of the value "at the well" (which is not attributable to the enhanced value of electricity generation), gross proceeds, or gross revenues of all lease products produced, saved, and sold on a monthly basis. In certain of our project subsidiaries' private leases, royalties payable to the lessor by the project subsidiary are based on the gross revenues received by the lessee from the sale or use of the geothermal substances, either from electricity production or the value of the geothermal resource "at the well".

In addition, pursuant to the leases, the project subsidiary typically agrees to commence drilling, extraction or processing operations on the leased land within the primary term, and to conduct such operations with reasonable diligence until lease products have been found, extracted and processed in quantities deemed "paying quantities" by the project subsidiary, or until further operations would, in such project subsidiary's judgment, be unprofitable or impracticable. The project subsidiary has the right at any time within the primary term to terminate the lease and surrender the relevant land. If the project subsidiary has not commenced any such operations on said land (or on the unit area, if the lease has been unitized), or terminated the lease within the primary term, the project subsidiary must pay to the lessor, in order to maintain its lease position, annually in advance, a rental fee until operations are commenced on the leased land.

If the project subsidiary fails to pay any installment of royalty or rental when due and if such default continues for a period of fifteen days specified in the lease, for example, after its receipt of written notice thereof from the lessor, then at the option of the lessor, the lease will terminate as to the portion or portions thereof as to which the project subsidiary is in default. If the project subsidiary defaults in the performance of any obligations under the lease, other than a payment default, and if, for a period of 90 days after written notice is given to it by the lessor of such default, the project subsidiary fails to commence and thereafter diligently and in good faith take remedial measures to remedy such default, the lessor may terminate the lease.

We do not regard any property that we lease as material unless and until we begin construction of a power plant on the property, that is, until we drill a production well on the property.

Exploration Concessions in Chile

We were awarded six exploration concessions in Chile, under which we had the rights to start exploration work with an original term of two years. Prior to the last six months of the original term of each exploration concession, we could request its extension for an additional period of two years. According to applicable regulations, the extension of the exploration concession is subject to the receipt by the Ministry of Energy of evidence that at least 25% of the planned investments for the execution of the project, as reflected in the relevant proposal submitted during the tender process, has been invested. Following submission of the request, the Ministry of Energy has three months in which it may grant or deny the extension. After conducting exploratory studies in those sites, we concluded that the geothermal resource would not support commercial operations at that time and we have waived five of the six concessions we held. Costs associated with exploration activities at these sites were expensed accordingly (see “Write-off of Unsuccessful Exploration Activities” under Item 7 — “Management’s Discussion and Analysis of Financial Condition and Results of Operations”). As of the date of this annual report we have the exclusive right to apply for an exploitation license for the remaining site. Our exclusive right will expire on March 7, 2016, and obtaining such license is subject to approval by the Ministry of Energy.

Description of Our Power Plants

Domestic Operating Power Plants

The following descriptions summarize certain industry metrics for our domestic operating power plants:

Brady Complex

Location	Churchill County, Nevada
Generating Capacity	18 MW
Number of Power Plants	Two (Brady and Desert Peak 2 power plants).
Technology	The Brady complex utilizes binary and flash systems. The complex uses air and water cooled systems.

Subsurface Improvements	12 production wells and eight injection wells are connected to the plants through a gathering system.
Major Equipment	Three OEC units and three steam turbines along with the Balance of Plant equipment.
Age	The Brady power plant commenced commercial operations in 1992 and a new OEC unit was added in 2004. The Desert Peak 2 power plant commenced commercial operation in 2007.
Land and Mineral Rights	The Brady complex is comprised mainly of BLM leases. The leases are held by production. The scheduled expiration dates for all of these leases are after the end of the expected useful life of the power plants. The complex's rights to use the geothermal and surface rights under the leases are subject to various conditions, as described in "Description of Our Leases and Lands".
Access to Property	Direct access to public roads from the leased property and access across the leased property are provided under surface rights granted pursuant to the leases, and the Brady power plant holds right of ways from the BLM and from the private owner that allows access to and from the plant.
Resource Information	The resource temperature at Brady is 271 degrees Fahrenheit and at Desert Peak 2 is 340 degrees Fahrenheit. The Brady and Desert Peak geothermal systems are located within the Hot Springs Mountains, approximately 60 miles northeast of Reno, Nevada, in northwestern Churchill County. The dominant geological feature of the Brady area is a linear NNE-trending band of hot ground that extends for a distance of two miles. The Desert Peak geothermal field is located within the Hot Springs Mountains, which form part of the western boundary of the Carson Sink. The structure is characterized by east-titled fault blocks and NNE-trending folds. Geologic structure in the area is dominated by high-angle normal faults of varying displacement.
Resource Cooling	During the last two years the cooling at Brady is leveling off to a rate of 1 degree a year. The temperature decline at Desert Peak is approximately two degrees Fahrenheit per year.
Sources of Makeup Water	Condensed steam is used for makeup water.
Power Purchaser	Brady power plant — Sierra Pacific Power Company. Desert Peak 2 power plant — Nevada Power Company.
PPA Expiration Date	Brady power plant — 2022. Desert Peak 2 power plant — 2027.

Financing	OFC Senior Secured Notes and ORTP Transaction in the case of the Brady power plant, and OPC Transaction in the case of Desert Peak 2 power plant.

Don A. Campbell Complex

Location	Mineral County, Nevada
Generating Capacity	41 MW
Number of Power Plants	Two
Technology	The Don A. Campbell power plant utilizes an air cooled binary system.
Subsurface Improvements	10 production wells and five injection wells are connected to the plant.

Material Equipment	Two air cooled OEC units with the Balance of Plant equipment.
Age	The Phase 1 power plant is in its second year of operation and the Phase 2 power plant commenced operation in September 2015.
Land and Mineral Rights	The Don A. Campbell area is comprised of BLM leases. Since we declared commercial operation, the leases are held by production, as described above in “Description of Our Leases and Lands”. The project’s rights to use the geothermal and surface rights under the leases are subject to various conditions, as described above in “Description of Our Leases and Lands”.
Resource Information	The Don A. Campbell geothermal reservoir consists of highly fractured, silicified alluvium over at least two square miles. Production and injection are very shallow with five pumped production wells (from depths of 1,350 feet to 1,900 feet) and three injection wells (from depths of 649 feet to 2,477 feet), all targeting northwest-dipping fractures. The thermal fluids are thought to be controlled by a combination of conductive heat transfer from deeper bedrock and through mixing of upwelling thermal fluids from a deeper geothermal system also contained in the bedrock. The system is considered blind with no surface expression of thermal features. The temperature of the resource is approximately 262 degrees Fahrenheit.
Resource Cooling	Since the beginning of operation, the resource temperature has been stable.
Access to Property	Direct access to public roads from the leased property and access across the leased property are provided under surface rights granted in leases from BLM.
Power Purchaser	Two separate PPAs with SCPPA
PPA Expiration Date	The Phase 1 PPA expires in 2034 and the Phase 2 PPA expires in 2036
Financing	Corporate funds and cash grant for Phase 1 that we received from the U.S. Treasury.
Supplemental Information	In April 2015, we closed an equity transaction with Northleaf in which Northleaf acquired a 36.75% equity interest in ORPD. ORPD owns the Puna complex, the Don A. Campbell phase 1 power plant, and the OREG 1, OREG 2, and OREG 3 power plants. See Item 7 - “Management’s Discussion and Analysis of Financial Condition and Results of Operations” under the heading “ORPD transaction”. Northleaf will purchase an approximately 36.75% equity interest in the Don A. Campbell phase 2 power plant, which will be added to the existing ORPD joint

venture according to the terms of the purchase agreement.

<u>Heber Complex</u>

Location	Heber, Imperial County, California
Generating Capacity	92 MW
Number of Power Plants	Five (Heber 1, Heber 2, Heber South, Gould 1 and Gould 2).
Technology	The Heber 1 plant is a dual flash system with a binary bottoming unit called Gould-1 and the Heber 2 group is comprised of the Heber 2, Gould 2 and Heber South plants which all utilize binary systems. The complex uses a water cooled system.

Subsurface Improvements	27 production wells and 38 injection wells connected to the plants through a gathering system.
Major Equipment	17 OEC units and one steam turbine with the Balance of Plant equipment.
Age	The Heber 1 plant commenced commercial operations in 1985 and the Heber 2 plant in 1993. The Gould 1 plant commenced commercial operation in 2006 and the Gould 2 plant in 2005. The Heber South plant commenced commercial operation in 2008.
Land and Mineral Rights	The total Heber area is comprised mainly of private leases. The leases are held by production. The scheduled expiration dates for all of these leases are after the end of the expected useful life of the power plants. The complex's rights to use the geothermal and surface rights under the leases are subject to various conditions, as described above in "Description of Our Leases and Lands".
Access to Property	Direct access to public roads from the leased property and access across the leased property are provided under surface rights granted pursuant to the leases.
Resource Information	The resource supplying the flash flowing Heber 1 wells averages 342 degrees Fahrenheit. The resource supplying the pumped Heber 2 wells averages 317 degrees Fahrenheit. Heber production is from deltaic sedimentary sandstones deposited in the subsiding Salton Trough of California's Imperial Valley. Produced fluids rise from near the magmatic heated basement rocks (18,000 feet) via fault/fracture zones to the near surface. Heber 1 wells produce directly from deep (4,000 to 8,000 feet) fracture zones. Heber 2 wells produce from the nearer surface (2,000 to 4,000 feet) matrix permeability sandstones in the horizontal outflow plume fed by the fractures from below and the surrounding ground waters. Scale deposition in the flashing Heber 1 producers is controlled by down hole chemical inhibition supplemented with occasional mechanical cleanouts and acid treatments. There is no scale deposition in the Heber 2 production wells.
Resource Cooling	An average of one degree Fahrenheit per year was observed during the past 20 years of production.
Sources of Makeup Water	Water is provided by condensate and by the IID.
Power Purchaser	One PPA with Southern California Edison and two PPAs with SCPPA.
PPA Expiration Date	Heber 1 — 2026, Heber 2 — 2023, and Heber South — 2031. The output from the Gould 1 and Gould 2 power plants is sold under the PPAs with Southern California Edison and SCPPA.

Financing	OrCal Senior Secured Notes and ORTP Transaction.
Supplemental Information	In 2013, we entered into a new PPA with SCPPA, which replaced the Heber 1 PPA with Southern California Edison that expired in December 2015.

Jersey Valley Power Plant

Location	Pershing County, Nevada
Generating Capacity	10 MW
Number of Power Plants	One
Technology	The Jersey Valley power plant utilizes an air cooled binary system.
Subsurface Improvements	Two production wells and four injection wells are connected to the plant through a gathering system. The third production well is not connected to the power plant and will be used in the future as required.

Major Equipment	Two OEC units together with the Balance of Plant equipment.
Age	Construction of the power plant was completed at the end of 2010 and the off-taker approved commercial operation status under the PPA effective on August 30, 2011.
Land and Mineral Rights	The Jersey Valley area is comprised of BLM leases. The leases are held by production. The scheduled expiration dates for all of these leases are after the end of the expected useful life of the power plant. The power plant's rights to use the geothermal and surface rights under the leases are subject to various conditions, as described above in "Description of Our Leases and Lands".
Access to Property	Direct access to public roads from leased property and access across leased property under surface rights granted in leases from BLM.
Resource Information	The Jersey Valley geothermal reservoir consists of a small high-permeability area surrounded by a large low-permeability area. The high-permeability area has been defined by wells drilled along an interpreted fault trending west-northwest. Static water levels are artesian; two of the wells along the permeable zone have very high productivities, as indicated by Permeability Index (PI) values exceeding 20 gpm/psi. The average temperature of the resource is 316 degrees Fahrenheit.
Resource Cooling	The rate of cooling was four degree Fahrenheit in 2015 but it has been moderating since injection in a well near the production wells was reduced and injection was increased at injection wells farther away by increasing injection pressure.
Power Purchaser	Nevada Power Company
PPA Expiration Date	2032
Financing	Corporate funds and ITC cash grant from the U.S. Treasury.

Mammoth Complex

Location	Mammoth Lakes, California
Generating Capacity	29 MW
Number of Power Plants	Three (G-1, G-2, and G-3).
Technology	The Mammoth complex utilizes air cooled binary systems.
Subsurface Improvements	Ten production wells and five injection wells are connected to the plants through a gathering system.

Major Equipment	Two new OECs and six Turbo-expanders together with the Balance of Plant equipment.
Age	The G-1 plant commenced commercial operations in 1984 and the G-2 and G-3 power plants commenced commercial operation in 1990. We recently replaced the equipment at the G-1 plant with new OECs.
Land and Mineral Rights	The total Mammoth area is comprised mainly of BLM leases. The leases are held by production. The scheduled expiration dates for all of these leases are after the end of the expected useful life of the power plants.
	The complex’s rights to use the geothermal and surface rights under the leases are subject to various conditions, as described above in “Description of Our Leases and Lands”.
Access to Property	Direct access to public roads from the leased property and access across the leased property are provided under surface rights granted pursuant to the leases.

Resource Information	The average resource temperature is 339 degrees Fahrenheit. The Casa Diablo/Basalt Canyon geothermal field at Mammoth lies on the southwest edge of the resurgent dome within the Long Valley Caldera. It is believed that the present heat source for the geothermal system is an active magma body underlying the Mammoth Mountain to the northwest of the field. Geothermal waters heated by the magma flow from a deep source (greater than 3,500 feet) along faults and fracture zones from northwest to southeast east into the field area. The produced fluid has no scaling potential.
Resource Cooling	In the last three years the temperature has stabilized and there is no notable decline, although one degree Fahrenheit per year was observed during the prior 20 years of production.
Power Purchaser	G1 and G3 plants - PG&E and G2 plant -Southern California Edison.
PPA Expiration Date	G-1 and G-3 plants 2034 and G-2 plant 2027.
Financing	OFC Senior Secured Notes and ORTP Transaction.

<u>McGinness Hills</u> <u>Complex</u>

Location	Lander County, Nevada
Generating Capacity	83 MW (after the 11 MW phase 2 power plant became operational on February 1, 2015)
Number of Power Plants	Two
Technology	The McGinness Hills complex utilizes an air cooled binary system.
Subsurface Improvements	10 production wells and five injection wells are connected to the power plant.
Material Equipment	Six air cooled OEC units with the Balance of Plant equipment.
Age	The first phase commenced commercial operation on July 1, 2012, and the second phase on February 1, 2015.
Land and Mineral Rights	The McGinness Hills area is comprised of private and BLM leases. The leases require annual rental payments, as described above in "Description of Our Leases and Lands". The rights to use the geothermal and surface rights under the leases are subject to various conditions, as described above in "Description of Our Leases and Lands".

Resource Information	The McGinness Hills geothermal reservoir is contained within a network of fractured rocks over an area at least three square miles. The reservoir is contained in both Tertiary intrusive and Paleozoic sedimentary (basement) rocks. The thermal fluids within the reservoir are inferred to flow upward through the basement rocks along the NNE-striking faults at several fault intersections. The thermal fluids then generally outflow laterally to the NNE and SSW along the NNE-striking faults. No modern thermal manifestations exist at McGinness Hills, although hot spring deposits encompass an area of approximately 0.25 square miles and indicate a history of surface thermal fluid flow. The resource temperature averages 335 degrees Fahrenheit and the fluids are sourced from the reservoir at elevations between 2,000 to 5,000 feet below the surface.
Resource Cooling	The temperature has been stable since the first phase began operation with no notable cooling.

Access to Property	Direct access to public roads from the leased property and access across the leased property are provided under surface rights granted in leases from BLM.
Power Purchaser	Nevada Power Company
PPA Expiration Date	2033
Financing	OFC 2 Senior Secured Notes and ITC cash grant from the U.S. Treasury for Phase 1.

North Brawley Power Plant

Location	Imperial County, California
Generating Capacity	18 MW (See supplemental information below)
Number of Power Plants	One
Technology	The North Brawley power plant utilizes a water-cooled binary system.
Subsurface Improvements	36 wells have been drilled and are connected to the plants through its gathering system. As we improved our knowledge of the reservoir, we moved some of the wells between production and injection and left some idle. Currently, we have 13 wells connected to the production header and 23 wells, connected to the injection header.
Major Equipment	Five OEC units together with the Balance of Plant equipment.
Age	The power plant commenced commercial operation on March 31, 2011.
Land and Mineral Rights	The total North Brawley area is comprised of private leases. The leases are held by production. The scheduled expiration date for all of these leases is after the end of the expected useful life of the power plant.
	The plant's rights to use the geothermal and surface rights under the leases are subject to various conditions, as described above in "Description of Our Leases and Lands".
Access to Property	Direct access to public roads from the leased property and access across the leased property are provided under surface rights granted pursuant to the leases.
Resource Information	North Brawley production is from deltaic and marine sedimentary sands and sandstones deposited in the subsiding Salton Trough of the Imperial Valley. Based on seismic refraction surveys the total thickness of these sediments in the Brawley area is over 15,000 feet. The shallow production reservoir (from depths of 1,500 to 4,500 feet) that was developed is fed by fractures and matrix permeability and is conductively heated from the underlying fractured reservoir which convectively

	circulates magmatically heated fluid. Produced fluid salinity ranges from 20,000 to 50,000 ppm, and the moderate scaling and corrosion potential is chemically inhibited. The temperature of the deeper fractured reservoir fluids exceed 525 degrees Fahrenheit, but the fluid is not yet developed because of severe scaling and corrosion potential. The deep reservoir is not dedicated to the North Brawley power plant. The average produced fluid resource temperature is 327 degrees Fahrenheit.
Resource Cooling	Temperature depends on operating production wells and declined 8 degrees last year.
Sources of Makeup Water	Water is provided by the IID.
Power Purchaser	Southern California Edison
PPA Expiration Date	2031

Financing	Corporate funds and ITC cash grant from the U.S. Treasury.
Supplemental Information	Since the North Brawley power plant was placed in service in 2010, it has been much more difficult to operate its geothermal field than other fields, and the power plant has been unable to reach its design capacity of 50 MW. Instead, it has been operating at capacities between 15 MW and 33 MW. This generation level has been achieved following significant additional capital expenditures and a higher than anticipated operating costs. We are currently selling the power generated by the North Brawley plant to Southern California Edison under the existing PPA at a capacity level of approximately 16 MW and we are planning to increase it to 18 MW by 2017. We intend to refrain from additional capital investment to expand the capacity and significantly reduced the operational costs of the North Brawley power plant until further geological analysis is completed and/or a higher energy rate is secured.

OREG 1 Power Plant

Location	Four gas compressor stations along the Northern Border natural gas pipeline in North and South Dakota.
Generating Capacity	22 MW
Number of Units	Four
Technology	The OREG 1 power plant utilizes our air cooled OEC units.
Major Equipment	Four WHOH and four OEC units together with the Balance of Plant equipment.
Age	The OREG 1 power plant commenced commercial operations in 2006.
Land	Easement from NBPL.
Access to Property	Direct access to the plant from public roads.
Power Purchaser	Basin Electric Power Cooperative
PPA Expiration Date	2031
Financing	Corporate funds.
Supplemental Information	In April 2015, we closed an equity transaction with Northleaf in which Northleaf acquired a 36.75% equity interest in ORPD. ORPD owns the Puna complex, the Don A. Campbell phase 1 power plant, and the OREG 1, OREG 2, and OREG 3 power plants. See Item 7 - “Management’s Discussion and Analysis of Financial Condition and Results of Operations” under the heading “ORPD transaction”.

OREG 2 Power Plant

Location	Four gas compressor stations along the Northern Border natural gas pipeline; one in Montana, two in North Dakota, and one in Minnesota.
Generating Capacity	22 MW
Number of Units	Four
Technology	The OREG 2 power plant utilizes our air cooled OEC units.
Major Equipment	Four WHOH and four OEC units together with the Balance of Plant equipment.
Age	The OREG 2 power plant commenced commercial operations during 2009.
Land	Easement from NBPL.

Access to Property	Direct access to the plant from public roads.
Power Purchaser	Basin Electric Power Cooperative
PPA Expiration Date	2034
Financing	Corporate funds.
Supplemental Information	In April 2015, we closed an equity transaction with Northleaf in which Northleaf acquired a 36.75% equity interest in ORPD. ORPD owns the Puna complex, the Don A. Campbell phase 1 power plant, and the OREG 1, OREG 2, and OREG 3 power plants. See Item 7 - "Management's Discussion and Analysis of Financial Condition and Results of Operations" under the heading "ORPD transaction".

OREG 3 Power Plant

Location	A gas compressor station along Northern Border natural gas pipeline in Martin County, Minnesota.
Generating Capacity	5.5 MW
Number of Units	One
Technology	The OREG 3 power plant utilizes our air cooled OEC units.
Major Equipment	One WHOH and one OEC unit along with the Balance of Plant equipment.
Age	The OREG 3 power plant commenced commercial operations during 2010.
Land	Easement from NBPL.
Access to Property	Direct access to the plant from public roads.
Power Purchaser	Great River Energy
PPA Expiration Date	2029
Financing	Corporate funds.
Supplemental Information	In April 2015, we closed an equity transaction with Northleaf in which Northleaf acquired a 36.75% equity interest in ORPD. ORPD owns the Puna complex, the Don A. Campbell phase 1 power plant, and the OREG 1, OREG 2, and OREG 3 power plants. See Item 7 - "Management's Discussion and Analysis of Financial Condition and Results of Operations" under the heading "ORPD transaction".

OREG 4 Power Plant

Location	A gas compressor station along natural gas pipeline in Denver, Colorado.
Generating Capacity	3.5 MW
Number of Units	One
Technology	The OREG 4 power plant utilizes our air cooled OEC units.
Major Equipment	Two WHOH and one OEC unit together with the Balance of Plant equipment.
Age	The OREG 4 power plant commenced commercial operations during 2009.
Land	Easement from Trailblazer Pipeline Company.
Access to Property	Direct access to the plant from public roads.
Power Purchaser	Highline Electric Association
PPA Expiration Date	2029
Financing	Corporate funds.

Ormesa Complex

Location	East Mesa, Imperial County, California
Generating Capacity	42 MW
Number of Power Plants	Three (OG I, OG II and GEM 3). The GEM 2 plant was taken off line during 2015 due to plant operation optimization.
Technology	The OG plants utilize a binary system and the GEM plant utilize a flash system. The complex uses a water cooling system.
Subsurface Improvements	24 production wells and 57 injection wells connected to the plants through a gathering system.
Material Major Equipment	8 OEC units and one steam turbines with the Balance of Plant equipment.
Age	The various OG I plants commenced commercial operations between 1987 and 1989, and the OG II plant commenced commercial operation in 1988. Between 2005 and 2007 a significant portion of the old equipment in the OG plants was replaced (including turbines through repowering). The GEM plant commenced commercial operation in 1989, and a new bottoming unit was added in 2007.
Land and Mineral Rights	The total Ormesa area is comprised of BLM leases. The leases are held by production. The scheduled expiration dates for all of these leases are after the end of the expected useful life of the power plants.
	The complex's rights to use the geothermal and surface rights under the leases are subject to various conditions, as described above in "Description of Our Leases and Lands".
Access to Property	Direct access to public roads from the leased property and access across the leased property are provided under surface rights granted pursuant to the leases.
Resource Information	The resource temperature is an average of 310 degrees Fahrenheit. Production is from sandstones.
	Productive sandstones are between 1,800 and 6,000 feet, and have only matrix permeability. The currently developed thermal anomaly was created in geologic time by conductive heating and direct outflow from an underlying convective fracture system. Produced fluid salinity ranges from 2,000 ppm to 13,000 ppm, and minor scaling and corrosion potential is chemically inhibited.
Resource Cooling	One degree Fahrenheit per year was observed during the past 20 years of production however, following shutdown of cold wells during 2015, temperature increased by approximately six degrees.
Sources of Makeup Water	Water is provided by the IID.

Power Purchaser	Southern California Edison under a single PPA.
PPA Expiration Date	December 2017
Financing	OFC Senior Secured Notes and ORTP Transaction.

Puna Complex

Location	Puna district, Big Island, Hawaii
Generating Capacity	38 MW

Number of Power Plants	Two
Technology	The Puna plants utilize our geothermal combined cycle and binary systems. The plants use an air cooled system.
Subsurface Improvements	Six production wells and five injection wells connected to the plants through a gathering system.
Major Equipment	One plant consists of ten OEC units made up of ten binary turbines, ten steam turbines and two bottoming units along with the Balance of Plant equipment. The second plant consists of two OEC units along with Balance of Plant equipment.
Age	The first plant commenced commercial operations in 1993. The second plant was placed in service in 2011 and commenced commercial operation in 2012.
Land and Mineral Rights	The Puna complex is comprised of a private lease. The private lease is between PGV and KLP and it expires in 2046. PGV pays an annual rental payment to KLP, which is adjusted every five years based on the CPI.
	The state of Hawaii owns all mineral rights (including geothermal resources) in the state. The state has issued a Geothermal Resources Mining Lease to KLP, and KLP in turn has entered into a sublease agreement with PGV, with the state's consent. Under this arrangement, the state receives royalties of approximately three percent of the gross revenues.
Access to Property	Direct access to the leased property is readily available via county public roads located adjacent to the leased property. The public roads are at the north and south boundaries of the leased property.
Resource Information	The geothermal reservoir at Puna is located in volcanic rock along the axis of the Kilauea Lower East Rift Zone. Permeability and productivity are controlled by rift-parallel subsurface fissures created by volcanic activity. They may also be influenced by lens-shaped bodies of pillow basalt which have been postulated to exist along the axis of the rift at depths below 7,000 feet.
	The distribution of reservoir temperatures is strongly influenced by the configuration of subsurface fissures and temperatures are among the hottest of any geothermal field in the world, with maximum measured temperatures consistently above 650 degrees Fahrenheit.
Resource Cooling	The resource temperature is stable.
Power Purchaser	Three PPAs with HELCO (see "Supplemental Information" below).
PPA Expiration Date	2027
Financing	Operating Lease and ITC cash grant from the U.S. Treasury. Also, in April 2015, we closed an equity transaction with Northleaf in which Northleaf acquired a

36.75% equity interest in ORPD. ORPD owns the Puna complex, the Don A. Campbell phase 1 power plant, and the OREG 1, OREG 2, and OREG 3 power plants. Discussed in Item 7 - "Management's Discussion and Analysis of Financial Condition and Results of Operations" under the heading "ORPD transaction".

Supplemental Information

The pricing for the energy that is sold from the Puna complex is as follows:

- For the first on-peak 25 MW, the energy price has not changed from HELCO avoided cost.
- For the next on-peak 5 MW, the price has changed from a diesel-based price to a flat rate of 11.8 cents per kWh escalated by 1.5% per year.

- For the new on-peak 8 MW, the price is 9 cents per kWh for up to 30,000 MWh/year and 6 cents per kWh above 30,000 MWh/year, escalated by 1.5% per year.
- For the first off-peak 22 MW the energy price has not changed from avoided cost.

The off-peak energy above 22 MW is dispatchable:

1. For the first off-peak 5 MW, the price has changed from diesel-based price to a flat rate of 11.8 cents per kWh escalated by 1.5% per year.
2. For the energy above 27 MW (up to 38 MW) the price is 6 cents per kWh, escalated by 1.5% per year.

The capacity payment for the first 30 MW remains the same ($160 kW/year for the first 25 MW and $100.95 kW/year for the additional 5 MW). For the new 8MW power plant the annual capacity payment is $2 million.

Steamboat Complex

Location	Steamboat, Washoe County, Nevada
Generating Capacity	73 MW
Number of Power Plants	Six (Steamboat 2 and 3, Burdette (Galena 1), Steamboat Hills, Galena 2 and Galena 3).
Technology	The Steamboat complex utilizes a binary system (except for Steamboat Hills, which utilizes a single flash system). The complex uses air and water cooling systems.
Subsurface Improvements	24 production wells and 10 injection wells connected to the plants through a gathering system.
Major Equipment	10 individual air cooled OEC units and one steam turbine together with the Balance of Plant Equipment.
Age	The power plants commenced commercial operation in 1992, 2005, 2007 and 2008. During 2008, the Rotoflow expanders at Steamboat 2 and 3 were replaced with four turbines manufactured by us.
Land and Mineral Rights	The total Steamboat area is comprised of 41% private leases, 41% BLM leases and 18% private land owned by us. The leases are held by production. The

scheduled expiration dates for all of these leases are after the end of the expected useful life of the power plants.

The complex's rights to use the geothermal and surface rights under the leases are subject to various conditions, as described above in "Description of Our Leases and Lands".

We have easements for the transmission lines we use to deliver power to our power purchasers.

Resource Information

The resource temperature is an average of 283 degrees Fahrenheit.

The Steamboat geothermal field is a typical basin and range geothermal reservoir. Large and deep faults that occur in the rocks allow circulation of ground water to depths exceeding 10,000 feet below the surface. Horizontal zones of permeability permit the hot water to flow eastward in an out-flow plume.

	The Steamboat Hills and Galena 2 power plants produce hot water from fractures associated with normal faults. The rest of the power plants acquire their geothermal water from the horizontal out-flow plume. The water in the Steamboat reservoir has a low total solids concentration. Scaling potential is very low unless the fluid is allowed to flash which will result in calcium carbonate scale. Injection of cooled water for reservoir pressure maintenance prevents flashing.
Resource Cooling	Historically, the resource temperature declined at two degrees Fahrenheit per year, however, since the expansion of the complex, the rate of decline has been approximately five degrees Fahrenheit per year (see "Supplemental Information" below). In 2015 temperature decline moderated to two degrees Fahrenheit since three injection wells were shut down in 2014.
Access to Property	Direct access to public roads from the leased property and access across the leased property are provided under surface rights granted pursuant to the leases.
Sources of Makeup Water	Water is provided by condensate and the local utility.
Power Purchaser	Sierra Pacific Power Company (for Steamboat 2 and 3, Burdette (Galena1), Steamboat Hills, and Galena 3) and Nevada Power Company (for Galena 2).
PPA Expiration Date	Steamboat 2 and 3 — 2022, Burdette (Galena1) — 2026, Steamboat Hills — 2018, Galena 3 — 2028, and Galena 2 — 2027.
Financing	OFC Senior Secured Notes and ORTP Transaction (Steamboat 2 and 3, and Burdette (Galena1)) and OPC Transaction (Steamboat Hills, Galena 2, and Galena 3)
Supplemental information	In an attempt to increase the output of the plant we have acquired land adjacent to the complex and are evaluating a resource development program on that land. Tracer tests and reservoir modeling showed that three injection wells were causing most of the cooling. We shut down these wells and drilled a new injection well in 2014, which we expect will reduce the complex cooling. One production well was connected to the plant and in 2016 we intend to tie in the new injection well that was drilled in 2014. We are planning to further optimize the field in 2016 to reduce cooling and maximize power output.

Tuscarora Power Plant

Location	Elko County, Nevada
Projected Generating Capacity	18 MW
Number of Power Plants	One

Technology	The Tuscarora power plant utilizes a water cooled binary system.
Subsurface Improvements	Three production and six injection wells are connected to the power plant.
Major Equipment	Two water cooled OEC units with the Balance of Plant equipment.
Age	The power plant commenced commercial operation on January 11, 2012.
Land and Mineral Rights	The Tuscarora area is comprised of private and BLM leases. The leases are currently held by payment of annual rental payments, as described above in “Description of Our Leases and Lands”. The plant’s rights to use the geothermal and surface rights under the leases are subject to various conditions, as described above in “Description of Our Leases and Lands”.

Resource Information	The Tuscarora geothermal reservoir consists of an area of approximately 2.5 square miles. The reservoir is contained in both Tertiary and Paleozoic (basement) rocks. The Paleozoic section consists primarily of sedimentary rocks, overlain by tertiary volcanic rocks. Thermal fluid in the native state of the reservoir flows upward and to the north through apparently southward-dipping, basement formations. At an elevation of roughly 2,500 feet with respect to mean sea level, the upwelling thermal fluid enters the tertiary volcanic rocks and flows directly upward, exiting to the surface at Hot Sulphur Springs.
	The resource temperature averages 337 degrees Fahrenheit.
Resource Cooling	We expect gradual decline in the cooling trend from two degrees Fahrenheit per year in the next two to three years, to less than one degree Fahrenheit per year over the long term.
Access to Property	Direct access to public roads from the leased property and access across the leased property are provided under surface rights granted in leases from BLM.
Sources of Makeup Water	Water is provided from five water makeup wells.
Power Purchaser	Nevada Power Company
PPA Expiration Date	2032
Financing	OFC 2 Senior Secured Notes and ITC cash grant from the U.S. Treasury.
Supplemental information	Due to the draught years, supply of make-up water for the plant cooling system is declining. With the increase in ambient temperatures, during the summer months we have experienced shortfall at levels that required at certain times reduction in plant generation. Engineering efforts for plant reconfiguration for partial air cooling are in progress.

Foreign Operating Power Plants

The following descriptions summarize certain industry metrics for our foreign operating power plants:

<u>Amatitlan Power Plant (Guatemala)</u>

Location	Amatitlan, Guatemala
Generating Capacity	20 MW
Number of Power Plants	One
Technology	

	The Amatitlan power plant utilizes an air cooled binary system and a small back pressure steam turbine (1 MW).
Subsurface Improvements	Five production wells and two injection wells connected to the plants through a gathering system.
Major Equipment	One steam turbine and two OEC units together with the Balance of Plant equipment.
Age	The plant commenced commercial operation in 2007.
Land and Mineral Rights	Total resource concession area (under usufruct agreement with INDE) is for a term of 25 years from April 2003. Leased and company owned property is approximately three percent of the concession area. Under the agreement with INDE, the power plant company pays royalties of 3.5% of revenues up to 20.5 MW generated and 2% of revenues exceeding 20.5 MW generated.

	The generated electricity is sold at the plant fence. The transmission line is owned by INDE.
Resource Information	The resource temperature is an average of 522 degrees Fahrenheit. The Amatitlan geothermal area is located on the north side of the Pacaya Volcano at approximately 5,900 feet above sea level. Hot fluid circulates up from a heat source beneath the volcano, through deep faults to shallower depths, and then cools as it flows horizontally to the north and northwest to hot springs on the southern shore of Lake Amatitlan and the Michatoya River Valley.
Resource Cooling	Approximately two degrees Fahrenheit per year.
Access to Property	Direct access to public roads from the leased property and access across the leased property are provided under surface rights granted pursuant to the lease agreement.
Power Purchasers	INDE and another local purchaser.
PPA Expiration Date	The PPA with INDE expires in 2028.
Financing	Senior secured limited recourse project finance loan from Banco Industrial S.A. and Westrust Bank (International) Limited.

Olkaria III Complex (Kenya)

Location	Naivasha, Kenya
Generating Capacity	139 MW
Number of Power Plants	Five (Olkaria III Phase 1 and Olkaria III Phase 2, together Plant 1, Plant 2, Plant 3 and Plant 4).
Technology	The Olkaria III complex utilizes an air cooled binary system.
Subsurface Improvements	18 production wells and five injection wells connected to the plants through a gathering system.
Major Equipment	13 OEC units together with the Balance of Plant equipment.
Age	Plant 4 commenced commercial operation in January 2015, Plant 3 in January 2014 and Plant 2 in April 2013. The first phase of Plant 1 commenced operation in 2000 and the second phase in 2009.
Land and Mineral Rights	

The total Olkaria III area is comprised of government leases. A license granted by the Kenyan government provides exclusive rights of use and possession of the relevant geothermal resources for an initial period of 30 years, expiring in 2029, which initial period may be extended for two additional five-year terms. The Kenyan Minister of Energy has the right to terminate or revoke the license in the event work in or under the license area stops during a period of six months, or there is a failure to comply with the terms of the license or the provisions of the law relating to geothermal resources. Royalties are paid to the Kenyan government monthly based on the amount of power supplied to the power purchaser and an annual rent.

The power generated is purchased at the metering point located immediately after the power transformers in the 220 kV sub-station within the power plant, before the transmission lines which belong to the utility.

Resource Information The resource temperature is an average of 570 degrees Fahrenheit.

	The Olkaria III geothermal field is on the west side of the greater Olkaria geothermal area located at approximately 6,890 feet above sea level within the Rift Valley.
	Hot geothermal fluids rise up from deep in the northeastern portion of the concession area, penetrating a low permeability zone below 3,280 feet above sea level to a high productivity, two-phase zone identified between 3,280 and 4,270 feet ASL.
Resource Cooling	The resource temperature is stable.
Access to Property	Direct access to public roads from the leased property and access across the leased property are provided under surface rights granted pursuant to the lease agreement.
Power Purchaser	KPLC
PPA Expiration Date	Plant 1 and 2 in 2033, Plant 3 in 2034 and Plant 4 in 2036
Financing	Senior secured project finance loan from OPIC and a subordinated loan from DEG.

Zunil Power Plant (Guatemala)

Location	Zunil, Guatemala
Generating Capacity	23 MW (see Supplemental Information below for information on current generating capacity)
Number of Power Plants	One
Technology	The Zunil power plant utilizes an air cooled binary system.
Subsurface	Six production wells and two injection wells are connected to the plant through a gathering system.
Major Equipment	Seven OEC units together with the Balance of Plant equipment.
Age	The plant commenced commercial operation in 1999.
Land and Mineral Rights	The land owned by the plant includes the power plant, workshop and open yards for equipment and pipes storage.
	Pipelines for the gathering system transit through a local agricultural area’s right of way acquired by us.
	The geothermal wells and resource are owned by INDE.

	Our produced power is sold at our property line; power transmission lines are owned and operated by INDE.
Resource Information	The Zunil geothermal reservoir is hosted in Tertiary volcanic rocks which include overly fractured granodiorite. Production wells produce a reservoir from 536-572 degrees Fahrenheit to a depth of approximately 2,860-4,300 feet. A shallow steam cap exists in the production area of the field, and most of the wells produce high enthalpy fluid due to the presence of two-phase conditions in their feed zones. The wells target northwest- and northeast-trending fractures for permeability. These fractures are also thought to control upwelling from the volcanically-heated source. The upwelling fluids form a steam cap, and fluids and steam reach the surface along fractures, forming springs and fumaroles throughout the geothermal field.
Resource Cooling	The resource temperature is stable.
Access to Property	Direct access to public roads.

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Power Purchaser	INDE
PPA Expiration Date	2034
Supplemental Information	In January 2014, we signed an amendment with INDE to extend the term of the PPA by 15 years until 2034. The PPA amendment also transfers operation and management responsibilities of the Zunil geothermal field from INDE to Ormat for the term of the amended PPA in exchange for an increase in tariff. Additionally, INDE exercised its right under the PPA to become a partner in the Zunil power plant and to hold a three percent equity interest. The power plant generates approximately 16 MW due to lack of sufficient geothermal resource supply. We successfully improved the heat supply and gradually increased the generation. We expect that this improvement and the increased tariff will increase the energy portion of revenues. We drilled a new production well in 2015 that increased the output of the power plant to its current level. According to the PPA amendment, payments for the Zunil plant will be made as follows:

1. Capacity payment:
   a. Until 2019, the capacity payment will be calculated based on 24 MW capacity regardless of the actual performance of the power plant.
   b. From 2019 and onwards, the capacity payment will be based on actual delivered capacity and the capacity rate will be reduced.
2. Energy payment:
   a. From January 2014 until 2034, the energy payment will include a geothermal field O&M rate based on actual delivered energy in addition to the energy rate on actual delivered energy.
   b. From 2019 and onwards, the energy rate on delivered energy will increase and will compensate the reduction in capacity price.

Projects under Construction

Some of our projects are in various stages of construction and include some projects that we have fully released for construction and two projects that are in initial stages of construction.

The following is a description of projects in Honduras and Indonesia that were released for, and are in different stages of, construction. These projects are expected to have a total generating capacity of 49 MW (Ormat’s share).

Platanares

Location	Copan, Honduras
Projected Generating Capacity	35 MW
Projected Technology	The plant will utilize an air cooled binary system.
Condition	Field development of the Platanares plant is in its initial stage. Production temperature is 354 degrees Fahrenheit with high productivity.

Subsurface Improvement	We have successfully drilled a production well and an injection well. In December 2015, we concluded the drilling activity as well as extensive tests that support the decision to construct a 35 MW project, which is larger than initially estimated.
Land and Mineral Rights	The project is located within a geothermal concession granted by the Department of Energy, Natural Resources, Environment, and Mines (SERNA), and located on fee land owned by GeoPlatanares and on land under lease from various private and public entities. The concession conveys to GeoPlatanares the right to exploit the geothermal resources contained within. The transmission corridor consists of easement agreements between GeoPlatanares and various private and public entities.
Resource Information	The project is located along a narrow river valley in western Honduras. The field is covered mostly by Miocene volcanic deposits. Numerous boiling hot springs and fumaroles emit along active faults along an area around two miles in length. The geothermal reservoir is supported by highly fractured volcanic and metasedimentary rock units. Wells are less than 800 meter deep.
Access to Property	Public roads provide access to the project area. In order to improve access for heavy equipment and large loads, GeoPlatanares has entered into a lease agreement with a private landowner for a small segment of road linking two leased parcels
Power Purchaser	30-year PPA with ENEE, the national utility of Honduras.
Financing	Corporate funds during construction.
Supplemental Information	We hold the assets, including the project's wells, land, permits and a PPA, under a BOT structure for 15 years from the date of commercial operation. Commercial operation is expected at the end of 2017.

<u>Sarulla (Indonesia)</u>

Location	Tapanuli Utara North Sumatra, Indonesia. One site is located in Silangkitan (SIL) and the two other sites in Namura I Langit (NIL) area.
Ownership	Sarulla Operation LTD (SOL) is a consortium consists of Medco Energi Internasional Tbk, Inpex Corporation, Itochu Corporation, Kyushu Electric Power Co. Inc., and one of our wholly owned subsidiaries that hold 12.75% interest.
Projected Generating Capacity	Approximately 330 MW
Projected Technology	Integrated Geothermal Combined Cycle Unit comprised of 3 back pressure steam turbines and 18 OEC units.
Condition	Engineering and procurement for the first phase has been completed but is still in progress for the other two phases. Construction for the first phase is in progress. The infrastructure work has been substantially completed. Major equipment, including Ormat's OECs and Toshiba's steam turbine, for the

first phase has arrived to the country and much of the equipment is already at the site. The drilling of production and injection wells is also in progress for all three phases, but currently the project company is experiencing some delays mainly in meeting some of the drilling milestones, as well as certain EPC milestones. It should also be noted that the project is facing certain cost overruns, resulting mainly from drilling. The consortium members are examining the significance of these cost overruns and their potential implications for the project's budget as well as for the financing of the project since the cost overruns and drilling delays may impact the project's ability to draw on the debt financing and force additional equity investment by the consortium members. All contractual milestones under Ormat’s supply agreement were achieved and the manufacturing work is currently progressing as planned.

Land and Mineral Rights	Most of the land for the project was acquired from private owners with some land leased from governmental agencies.
Resource Information	Two field areas, NIL and SIL host a liquid-dominated system. Previously drilled wells have temperatures from 275°C to 310°C. Flow tests of the first SOL partnership well, N2n-1, predict 22 NMW single well capacity with 751 T/hr total flow and 125 T/hr steam flow at 12.5 bar and 1126 kJ/kg. Both fields are within a tectonic half graven adjacent to the Great Sumatran Fault. In addition to highly encouraging production results, extensive surface manifestations, including fumaroles, boiling hot springs, and alteration, highlight an extensive area of productivity.
Access to Property	Access to property for the project has been secured.
Power Purchaser	30-year Energy Sales Contract with PT PLN (the state electric utility)
Financing	In May, 2014, the consortium reached financial closing of $1.17 billion to finance the development of the project with a consortium of lenders comprised of Japan Bank for International Cooperation (“JBIC”), the Asian Development Bank and six commercial banks and obtained construction and term loan under limited recourse financing package backed by political risk guarantee from JBIC.
Projected Operation	The project will be constructed in three phases of approximately 110 MW each, utilizing both steam and brine extracted from the geothermal field to increase the power plant’s efficiency. The first phase of operations is expected to commence in 2016 and the remaining two phases of operations are scheduled to commence within 18 months thereafter.
Supplemental Information	The Sarulla project will be owned and operated by the consortium members under the framework of a JOC and ESC. Under the JOC, PT Pertamina Geothermal Energy (PGE), the concession holder for the project, has provided the consortium with the right to use the geothermal field, and under the ESC, PT PLN, the state electric utility, will be the off-taker at Sarulla for a period of 30 years. In addition to our equity holdings in the consortium, we designed the Sarulla plant and will supply our OECs to the power plant.

The following is a description of projects in California and Nevada with an expected total generating capacity of 50 MW that are each in an initial stage of construction:

Carson Lake Project (U.S.)

Location	Churchill County, Nevada
Projected Generating Capacity	20 MW
Projected Technology	The Carson Lake power plant will utilize a binary system.

Condition	Initial stage of construction.
Subsurface Improvements	On hold.
Land and Mineral Rights	The Carson Lake area is comprised of BLM leases.

	The leases are currently held by the payment of annual rental payments, as described above in "Description of Our Leases and Lands."
	Unless steam is produced in commercial quantities, the primary term for these leases will expire commencing August 31, 2016. Ormat is considering to extending the terms of the leases.
	The project's rights to use the geothermal and surface rights under the leases are subject to various conditions, as described above in "Description of Our Leases and Lands".
Access to Property	Direct access to public roads from the leased property and access across the leased property are provided under surface rights granted in leases from BLM.
Resource Information	The expected average temperature of the resource cannot be estimated as field development has not been completed yet.
Power Purchaser	We have not executed a PPA.
Financing	Corporate funds.
Projected Operation	To be determined.
Supplemental Information	Permitting documentation for the power plant was completed.

CD4 Project (Mammoth Complex) (U.S.)

Location	Mammoth Lakes, California
Projected Generating Capacity	30 MW
Projected Technology	The CD4 power plant will utilize an air cooled binary system.
Condition	Initial stage of construction.
Subsurface Improvements	We have completed one production well and one injection well. Continued drilling is subject to receipt of additional permits.
Land and Mineral Rights	The total Mammoth area is comprised mainly of BLM leases, which are held by production and are the subject of a unitization agreement.
Access to Property	

	Direct access to public roads from the leased property and access across the leased property are provided under surface rights granted pursuant to the leases.
Resource Information	The expected average temperature of the resource cannot be estimated as field development has not been completed yet.
Power Purchaser	We have not executed a PPA.
Financing	Corporate funds.
Projected Operation	To be determined.
Supplemental Information	As part of the process to secure a transmission line, we are participating in the Southern California Edison Wholesale Distribution Access Tariff Transition Cluster Generator Interconnection Process (WDAT LGIA) to deliver energy into the Southern California Edison system at the Casa Diablo Substation. Southern California Edison completed phase I and phase II cluster studies and the WDAT LGIA is being reviewed while re-evaluation of the system upgrades is being completed due to changes in the participants in the cluster study.

Future Projects

Projects under Various Stages of Development

We also have projects under various stages of development in the U.S., and Kenya. We expect to continue to explore these and other opportunities for expansion so long as they continue to meet our business objectives and investment criteria.

The following is a description of the projects currently under various stages of development and for which we are able to estimate their expected generating capacity. Upon completion of these projects, the generating capacity of the geothermal projects would be up to approximately 90 MW (representing our interest). However, we prioritize our investments based on their readiness for continued construction and expected economics and therefore we are not planning to invest in all of such projects in 2016.

e-Bay REG Project (U.S.)

In September 2013, we entered a Joint Development Agreement with eBay Inc. for the development of a five-megawatt REG power plant to be constructed in Utah. The Joint Development Agreement allows Ormat and eBay Inc. to advance negotiations on a 20-year term contract and begin preliminary development work to supply cleaner electricity to eBay Inc.'s new Salt Lake City-based data center.

Tungsten Mountain (Nevada)

We are developing the Tungsten Mountain project on BLM leases located in Churchill County, Nevada. We expect the project to be between 25 to 35 MW.

We have drilled several exploration wells and drilling activity is ongoing. We secured an interconnection agreement and are in final stages of obtaining the major construction permits. We signed a non-binding letter of intent with a potential California off-taker and expect to secure a PPA in 2016. We expect to reach commercial operation in 2017.

Dixie Meadows (Nevada)

We are developing the Dixie Meadows project on BLM leases located in Churchill County, Nevada. We expect the project to be between 25 to 35 MW.

We have drilled several exploration wells and drilling activity is ongoing. We secured an interconnection agreement and are in advanced stages of obtaining the major construction permits. PPA is expected to be secured in 2016. We expect to reach commercial operation in 2017 or 2018**.**

Menengai Project (Kenya)

On November 3, 2014, our majority owned Kenyan subsidiary (the Project Company) owned by Ormat (51%), Symbion Power LLC (24.5%) and Civicon Ltd. (24.5%), signed a 25-year PPA with KPLC and a project implementation and steam supply agreement (PISSA) with GDC for the 35 MW Menengai geothermal project in Kenya.

Under the PISSA agreement, the Project Company will finance, design, construct, install, operate and maintain the 35 MW Menengai steam plant on a build-own-operate (BOO) basis for 25 years. GDC, which is wholly owned by the Government of Kenya, will develop the geothermal resource, supply the steam for conversion to electricity and maintain the geothermal field through the term of the agreement. The Project Company expects to start construction upon financial closing.

Future Prospects

We have a substantial land position that is expected to support future development on which we have started or plan to start exploration activity. When deciding whether to continue holding lease rights and/or to pursue exploration activity, we diligently prioritize our prospective investments, taking into account resource and probability assessments in order to make informed decisions about whether a particular project will support commercial operations. As a result, during fiscal year 2015, we discontinued exploration activities at ten future prospects, including Kona and Ulupalakua (Maui) in Hawaii, Warm Springs Tribe and Newberry - Twilight in Oregon, Whirlwind Valley in Utah, Argenta, Hycroft and South Jersey in Nevada and Mariman and Quinohuen in Chile.

Our current land position is comprised of various leases and private land for geothermal resources of approximately 159,000 acres in 29 prospects including the following:

Nevada [11]

1. Aqua Quieta	Completed exploration studies;
2. Baltazor	Completed exploration studies;
3. Beowawe	Under exploration studies;
4. Dixie Comstock	Under exploration studies;
5. Don A. Campbell - Phase 3	Assessment of future expansion;
6. Edwards Creek	Under exploratory drilling;
7. South Brady	Assessment of future expansion;
8. McGinness Hills - Phase 3	Assessment of future expansion;
9. North Valley	Completed exploration studies;
10. Trinity	Under exploration studies; and
11. Tuscarora – Phase 2	Completed exploration studies.

California [4]

1. East and North Brawley	Deep resource - lease acquired but no further action has yet been taken;
2. Glamis	Lease acquired but no further action has yet been taken;
3. Rhyolite Plateau	Lease acquired but no further action has yet been taken; and
4. Truckhaven	Under exploration studies.

Hawaii [1]

1. Kula	Lease acquired but no further action has yet been taken;

Oregon [3]

1. Crump Geyser	Completed exploration drilling
2. Glass Buttes - Midnight Point	Under exploratory drilling; and
3. Lakeview/ Goose Lake	Completed exploration studies.

New Mexico [1]

1. Rincon	Completed exploration studies.

Guatemala [2]

1. Amatitlan Phase II	Exploration studies underway and are subject to acquisition of additional land; and
2. Tecumburu	Under exploration studies.

New Zealand [1]

1. Tikitere	Signed BOT agreement; exploratory drilling is pending resource consent acceptance

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Kenya [1]

1. Olkaria III – plant 4 expansion	Assessment of future expansion;

Chile [1]

1. Sollipulli	Under exploration studies.

Ethiopia (4)

1. Boku	Concessions awarded
2. Dofan	Concessions awarded
3. Shashamane	Concessions awarded
4. Dugumo Fango	Concessions awarded

We also have an option to enter into a geothermal lease in Oregon covering approximately 44,000 acres under a lease option agreement with Weyerhaeuser Company. We are currently exploring the following prospects:

1. Winema	Started exploration studies.

Operations of our Product Segment

Power Units for Geothermal Power Plants. We design, manufacture, and sell power units for geothermal electricity generation, which we refer to as OECs. Our customers include contractors and geothermal plant owners and operators.

The power units are usually paid for in installments, in accordance with milestones set in the supply agreement. Sometimes we agree to provide the purchaser with spare parts (or alternatively, with a non-exclusive license to manufacture such parts). We provide the purchaser with at least a 12-month warranty for such products. We usually also provide the purchaser (often, upon receipt of advances made by the purchaser) with a guarantee, which expires in part upon delivery of the equipment to the site and fully expires at the termination of the warranty period. The guarantees are typically supported by letters of credit.

Power Units for Recovered Energy-Based Power Generation. We design, manufacture, and sell power units used to generate electricity from recovered energy or so-called “waste heat”. Our existing and target customers include interstate natural gas pipeline owners and operators, gas processing plant owners and operators, cement plant owners and operators, and other companies engaged in other energy-intensive industrial processes. We have two different business models for this product line.

The first business model, which is similar to the model utilized in our geothermal power generation business, consists of the development, construction, ownership, and operation of recovered energy-based generation power plants. In this case, we will enter into agreements to purchase industrial waste heat, and enter into long-term PPAs with off-takers to sell the electricity generated by the REG unit that utilizes such industrial waste heat. The power purchasers in such cases generally are investor-owned electric utilities or local electrical cooperatives. This is the business model for our OREG 1, 2, 3 and 4 power plants.

Pursuant to the second business model, we construct and sell the power units for recovered energy-based power generation to third parties for use in “inside-the-fence” installations or otherwise. Our customers include gas processing plant owners and operators, cement plant owners and operators and companies in the process industry.

Remote Power Units and other Generators. We design, manufacture and sell fossil fuel powered turbo-generators with capacities ranging from 200 watts to 5,000 watts, which operate unattended in extreme hot or cold climate conditions. The remote power units supply energy for remote and unmanned installations and along communications lines, and cathodic protection along gas and oil pipelines. Our customers include contractors installing gas pipelines in remote areas. In addition, we manufacture and sell generators, including heavy duty direct current generators, for various other uses. The terms of sale of the turbo-generators are similar to those for the power units we produce for power plants.

EPC of Power Plants. We engineer, procure and construct, as an EPC contractor, geothermal and recovered energy power plants on a turnkey basis, using power units we design and manufacture. Our customers are geothermal power plant owners as well as our target customers for the sale of our recovered-energy based power units described above. Unlike many other companies that provide EPC services, we believe we have an advantage in that we are using our own manufactured equipment and thus have better quality and better control over the timing and delivery of required equipment and its related costs. The consideration for such services is usually paid in installments, in accordance with milestones set in the EPC contract and related documents. We usually provide performance guarantees or letters of credit securing our obligations under the contract. Upon delivery of the plant to its owner, such guarantees are replaced with a warranty guarantee, usually for a period ranging from 12 months to 36 months. The EPC contract usually places a cap on our liabilities for failure to meet our obligations thereunder.

In connection with the sale of our power units for geothermal power plants, power units for recovered energy-based power generation, remote power units and other generators, we enter, from time to time, into sales agreements with sales representatives for the marketing and sale of such products pursuant to which we are obligated to pay commissions to such representatives upon the sale of our products in the relevant territory covered by such agreements by such representatives or, in some cases, by other representatives in such territory.

Our manufacturing operations and products are certified ISO 9001, ISO 14001, American Society of Mechanical Engineers, and TÜV, and we are an approved supplier to many electric utilities around the world.

Backlog

We have a product backlog of approximately $256.3 million as of February 23, 2016, which includes revenues for the period between January 1, 2016 and February 23, 2016, compared to $325.8 million as of February 26, 2015, which included revenues for the period between January 1, 2015 and February 26, 2015.

The following is a breakdown of the Product segment backlog as of February 23, 2016 ($ in millions):

	Expected Completion of the Contract	Sales Expected to be Recognized in 2016	Sales Expected to be Recognized in the years following 2016	Expected Until End of Contract
Geothermal	2017	176.0	62.5	238.5
Recovered Energy	2016	8.2	-	8.2
Remote Power Units	2016	2.3	-	2.3
Other	2017	4.1	3.2	7.3
Total		**190.6**	**65.7**	**256.3**

Competition

In our Electricity segment, we face competition from geothermal power plant owners and developers as well as other renewable energy providers.

In our Product segment, we face competition from power plant equipment manufacturers or system integrators and from engineering or projects management companies.

As we implement our new strategic plan, we will face competition from a number of sources, many of which may have resources, industry experience, market acceptance or other advantages we do not have. For example, expanding into new technologies, such as energy storage, or markets, such as C&I will involve competition both from companies that already have established businesses in those technologies and markets, other companies seeking to acquire established businesses and other new market entrants like us.

Electricity Segment

Competition in the Electricity segment is particularly marked in the very early stage of either obtaining the rights to the resource for the development of future projects or acquiring a site already in a more advanced stage of development. Once we or other developers obtained such rights or own a power plant, competition is limited. From time to time and in different jurisdictions competing geothermal developers become our customers in the Product segment.

The main companies competing with us in the geothermal sector in the U.S. are CalEnergy, Calpine Corporation, Terra-Gen Power LLC, Enel Green Power S.p.A and other smaller-sized pure play developers. Outside the U.S., in many cases our competitors are companies that are gaining experience developing geothermal projects in their own countries such as Mighty River Power (MRP) from New Zealand and Origin Energy from Australia. Some of our competitors are now seeking to take the local experience they have gained and develop geothermal projects in other countries. These competitors include Energy Development Corporation (EDC) from the Philippines, Contact Energy Limited from New Zealand, Tata Group from India and Enel Green Power from Italy. Additionally, we see competition from small country-specific companies. While the geothermal industry is characterized by high barriers to entry, national electric utilities or state-owned oil companies might also enter the market.

In obtaining new PPAs, we also face competition from companies engaged in the power generation business from other renewable energy sources, such as wind power, biomass, solar power and hydro-electric power. In the last few years, competition from the wind and solar power generation industries has increased significantly.

As a geothermal company, we are focused on niche markets where our site-specific and base load advantages can allow us to develop competitive projects.

Product Segment

Our competitors among power plant equipment suppliers are divided into: high enthalpy and low enthalpy competitors. Our main high enthalpy competitors are industrial steam turbine manufacturers such as Mitsubishi Hitachi Power Systems, Fuji Electric Co., Ltd. and Toshiba of Japan, GE/Nuovo Pignone brand and Ansaldo Energia of Italy. As noted above, we recently signed a strategic collaboration agreement with an affiliate of one of these competitors, Toshiba Corporation.

Our low enthalpy competitors are binary systems manufacturers using the Organic Rankine Cycle such as Fuji Electric Co., Ltd of Japan, Atlas Copco Company, Exergy of Italy, and Mitsubishi Hitachi Power Systems (which acquired Turboden). While we believe that we have a distinct competitive advantage based on our accumulated experience and current worldwide share of installed binary generation capacity (which is approximately 90%), an increase in competition, which we are currently experiencing, has started to impact our ability to secure new purchase orders from potential customers. The increased competition may also lead to a reduction in the prices that we are able to charge for our binary equipment, which in turn may impact our profitability.

In the REG business, our competitors are other Organic Rankine Cycle manufacturers (such as GE and Mitsubishi/Turboden), manufactures that use Kalina technology (such as Geothermal Energy Research & Development Co., Ltd in Japan), as well as other manufacturers of conventional steam turbines.

In the remote power unit business, we face competition from Global Thermoelectric, as well as from manufacturers of diesel generator sets and small wind and solar installations with batteries.

Currently, none of our competitors compete with us in both the Electricity and the Product segments.

In the case of proposed EPC projects we also compete with other service suppliers, such as project/engineering companies.

Customers

All of our revenues from the sale of electricity in the year ended December 31, 2015 were derived from fully-contracted energy and/or capacity payments under long-term PPAs with governmental and private utility entities. Southern California Edison, Sierra Pacific Power Company and Nevada Power Company (subsidiaries of NV Energy), HELCO, and SCPPA accounted for 9.4%, 19.5%, 4.8% and 5.0% of total revenues, respectively, for the year ended December 31, 2015. Based on publicly available information, as of December 31, 2015, the issuer ratings of Southern California Edison, HELCO, Sierra Pacific Power Company, Nevada Power Company, SCPPA and Pacific Gas & Electric were as set forth below:

Issuer	Standard & Poor's Ratings Services	Moody's Investors Service Inc.
Southern California Edison	BBB+ (stable outlook)	A2 (stable outlook)
HELCO	BBB- (Watch)	Rating Withdrawn
Sierra Pacific Power Company	BBB+ (stable outlook)	Baa1 (stable outlook)
Nevada Power Company	BBB+ (stable outlook)	Baa1 (stable outlook)
SCPPA	BBB+ (Stable outlook)	Aa3 (stable outlook)
Pacific, Gas and Electric	BBB (Positive outlook)	A3 (stable outlook)

The credit ratings of any power purchaser may change from time to time. There is no publicly available information with respect to the credit rating or stability of the power purchasers under the PPAs for our foreign power plants.

Our revenues from the Product segment are derived from contractors or owners or operators of power plants, process companies, and pipelines.

Raw Materials, Suppliers and Subcontractors

In connection with our manufacturing activities, we use raw materials such as steel and aluminum. We do not rely on any one supplier for the raw materials used in our manufacturing activities, as all of these raw materials are readily available from various suppliers.

We use subcontractors for some of the manufacturing of our products components and for construction activities of our power plants, which allows us to expand our construction and development capacity on an as-needed basis. We are not dependent on any one subcontractor and expect to be able to replace any subcontractor, or assume such manufacturing and construction activities of our projects ourselves, without adverse effect to our operations.

Employees

As of December 31, 2015, we employed 1,060 employees, of which 448 were located in the U.S., 499 were located in Israel and 113 were located in other countries. We expect that future growth in the number of our employees will be mainly attributable to the purchase and/or development of new power plants.

As of the date of this report, none of our employees are represented by a labor union, and we have never experienced any labor dispute, strike or work stoppage. We consider our relations with our employees to be satisfactory. We believe our future success will depend on our continuing ability to hire, integrate, and retain qualified personnel.

In the U.S., we currently do not have employees represented by unions recognized by the company under collective bargaining agreements. However, a union has filed a petition with the National Labor Relations Board (NLRB) in an attempt to organize our employees at our Puna complex in Hawaii. The NLRB ruled that a certification of representative should be issued. The Company appealed the NLRB decision and the matter was pending before the U.S. Court of Appeals for the Ninth Circuit in California before being remanded back to the NLRB. As of the date of this report, the NLRB has put on hold its request for a hearing to bring unfair labor practice allegations before an administrative law judge in view of ongoing settlement discussions.

We have no collective bargaining agreements with respect to our Israeli employees. However, by order of the Israeli Ministry of Economy and Industry, the provisions of a collective bargaining agreement between the Histadrut (the General Federation of Labor in Israel) and the Coordination Bureau of Economic Organizations (which includes the Industrialists Association) may apply to some of our Israeli non-managerial, finance and administrative, and sales and marketing personnel. This collective bargaining agreement principally concerns cost of living pay increases, length of the workday, minimum wages and insurance for work-related accidents, annual and other vacation, sick pay, and determination of severance pay, pension contributions, and other conditions of employment. We currently provide such employees with benefits and working conditions which are at least as favorable as the conditions specified in the collective bargaining agreement.

Insurance

We maintain business interruption insurance, casualty insurance, including flood, volcanic eruption and earthquake coverage, and primary and excess liability insurance, control of wells, as well as customary worker's compensation and automobile, marine transportation insurance and such other commercial insurance, if any, as is generally carried by companies engaged in similar businesses and owning similar properties in the same general areas or as may be required by any of our PPAs, or any lease, financing arrangement, or other contract. To the extent any such casualty insurance covers both us and/or our power plants, and any other person and/or plants, we generally have specifically designated as applicable solely to us and our power plants "all risk" property insurance coverage in an amount based upon the estimated full replacement value of our power plants (provided that earthquake, volcanic eruption and flood coverage may be subject to annual aggregate limits depending on the type and location of the power plant) and business interruption insurance in an amount that also varies from power plant to power plant.

We generally purchase insurance policies to cover our exposure to certain political risks involved in operating in developing countries. Political risk insurance policies are generally issued by entities which specialize in such policies, such as MIGA (a member of the World Bank Group), or by private sector providers, such as Lloyd Syndicates, Zurich Emerging Markets and other such companies. To date, all of our political risk insurance contracts are with the Multilateral Investment Guarantee Agency and with Zurich Emerging Markets. Currently we hold such insurance for our Zunil and Olkaria operating power plants, and for the Sarulla project, which is under construction. Such insurance policies generally cover, subject to the limitations and restrictions contained therein, approximately 90% of our losses derived from a specified governmental act, such as confiscation, expropriation, riots, and the inability to convert local currency into hard currency and, in certain cases, the breach of agreements with governmental entities.

Regulation of the Electric Utility Industry in the United States

The following is a summary overview of the electric utility industry and applicable federal and state regulations, and should not be considered a full statement of the law or all issues pertaining thereto.

PURPA

PURPA provides the owners of power plants certain benefits described below, if a power plant is a "Qualifying Facility". A small power production facility is a Qualifying Facility if: (i) the facility does not exceed 80 MW; (ii) the primary energy source of the facility is biomass, waste, renewable resources, or any combination thereof, and at least 75% of the total energy input of the facility is from these sources, and fossil fuel input is limited to specified uses; and (iii) the facility, if larger than one megawatt, has filed with FERC a notice of self-certification of qualifying status, or has filed with FERC an application for FERC certification of qualifying status, that has been granted. The 80 MW size limitation, however, does not apply to a facility if (i) it produces electric energy solely by the use, as a primary energy input, of solar, wind, waste or geothermal resources; and (ii) an application for certification or a notice of self-certification of qualifying status of the facility was submitted to FERC prior to December 21, 1994, and construction of the facility commenced prior to December 31, 1999.

FERC's regulations under PURPA exempt owners of small power production Qualifying Facilities that use geothermal resources as their primary source and other Qualifying Facilities that are 30 MW or under in size from regulation under the PUHCA 2005, from many provisions of the FPA and from state laws relating to the financial, organization and rate regulation of electric utilities.

With respect to the FPA, FERC's regulations under PURPA do not exempt from the rate provisions of the FPA sales of energy or capacity from Qualifying Facilities larger than 20 MW in size that are made (a) pursuant to a contract executed after March 17, 2006 that is not a contract made pursuant to a state regulatory authority’s implementation of PURPA or (b) not pursuant to another provision of a state regulatory authority’s implementation of PURPA. The practical effect of these regulations is to require owners of Qualifying Facilities that are larger than 20 MW in size to obtain market-based rate authority from FERC if they seek to sell energy or capacity other than pursuant to a contract executed before March 17, 2006 pursuant to a state regulatory authority’s implementation of PURPA or pursuant to a provision of a state regulatory authority’s implementation of PURPA. Until that contract expires, is terminated or is materially modified, a Qualifying Facility, under a PURPA contract executed prior to March 17, 2006, will not be required to file for market based rates.

In addition, PURPA and FERC’s regulations under PURPA require that electric utilities offer to purchase electricity generated by Qualifying Facilities at a rate based on the purchasing utility’s incremental cost of purchasing or producing energy (also known as “avoided cost”). However, FERC's regulations under PURPA also allow FERC, upon request of a utility, to terminate a utility’s obligation to purchase energy from Qualifying Facilities upon a finding that Qualifying Facilities have nondiscriminatory access to either: (i) independently administered, auction-based day ahead, and real time markets for energy and wholesale markets for long-term sales of capacity; (ii) transmission and interconnection services provided by a FERC-approved regional transmission entity and administered under an open-access transmission tariff that affords nondiscriminatory treatment to all customers, and competitive wholesale markets that provide a meaningful opportunity to sell capacity and energy, including long and short term sales; or (iii) wholesale markets for the sale of capacity and energy that are at a minimum of comparable competitive quality as markets described in (i) and (ii) above. FERC regulations protect a Qualifying Facility’s rights under any contract or obligation involving purchases or sales that are entered into before FERC has determined that the contracting utility is entitled to relief from the mandatory purchase obligation. FERC has granted the request of California investor-owned utilities for a waiver of the mandatory purchase obligation for Qualifying Facilities larger than 20 MW in size.

We expect that our power plants in the U.S will continue to meet all of the criteria required for Qualifying Facilities under PURPA. However, since the Heber power plants have PPAs with Southern California Edison that require Qualifying Facility status to be maintained, maintaining Qualifying Facility status remains a key obligation. If any of the Heber power plants loses its Qualifying Facility status our operations could be adversely affected. Loss of Qualifying Facility status would eliminate the Heber power plants’ exemption from the FPA and thus, among other things, the rates charged by the Heber power plants in the PPAs with Southern California Edison and SCPPA would become subject to FERC regulation. Further, it is possible that the utilities that purchase power from the power plants could successfully obtain a waiver of the mandatory-purchase obligation in their service territories. For example, the three California investor-owned utilities have received such a waiver from FERC for projects larger than 20 MW. If this occurs, the power plants’ existing PPAs will not be affected, but the utilities will not be obligated under PURPA to renew these PPAs or execute new PPAs upon the existing PPAs’ expiration.

PUHCA

Under PUHCA 2005, the books and records of a utility holding company, its affiliates, associate companies, and subsidiaries are subject to FERC and state commission review with respect to transactions that are subject to the jurisdiction of either FERC or the state commission or costs incurred by a jurisdictional utility in the same holding company system. However, if a company is a utility holding company solely with respect to Qualifying Facilities, exempt wholesale generators, or foreign utility companies, it will not be subject to review of books and records by FERC under PUHCA 2005. Qualifying Facilities that make only wholesale sales of electricity are not subject to state commissions’ rate regulations and, therefore, in all likelihood would not be subject to any review of their books and records by state commissions pursuant to PUHCA 2005 as long as the Qualifying Facility is not part of a holding company system that includes a utility subject to regulation in that state.

FPA

Pursuant to the FPA, FERC has exclusive jurisdiction over the rates for most wholesale sales of electricity and transmission in interstate commerce. These rates may be based on a cost of service approach or may be determined on a market basis through competitive bidding or negotiation. FERC's regulations under PURPA exempt owners of small power production Qualifying Facilities that use geothermal resources as their primary source and other Qualifying Facilities that are 30 MW or under in size from many provisions of the FPA. If any of the power plants were to lose its Qualifying Facility status, such power plant could become subject to the full scope of the FPA and applicable state regulations. The application of the FPA and other applicable state regulations to the power plants could require our power plants to comply with an increasingly complex regulatory regime that may be costly and greatly reduce our operational flexibility. Even if a power plant does not lose Qualifying Facility status, if a PPA with a power plant expires, is terminated or is materially modified, the owner of a Qualifying Facility power plant in excess of 20 MW will become subject to rate regulation under the Federal Power Act.

If a power plant in the U.S. were to become subject to FERC’s ratemaking jurisdiction under the FPA as a result of loss of Qualifying Facility status and the PPA remains in effect, FERC may determine that the rates currently set forth in the PPA are not just and reasonable and may set rates that are lower than the rates currently charged. In addition, FERC may require that the power plant refund a portion of amounts previously paid by the relevant power purchaser to such power plant. Such events would likely result in a decrease in our future revenues or in an obligation to disgorge revenues previously earned by from the power plant, either of which would have an adverse effect on our revenues.

Moreover, the loss of the Qualifying Facility status of any of our power plants selling energy to Southern California Edison could also permit Southern California Edison, pursuant to the terms of its PPA, to cease taking and paying for electricity from the relevant power plant and to seek refunds for past amounts paid. In addition, the loss of any such status would result in the occurrence of an event of default under the indenture for the OFC Senior Secured Notes and the OrCal Senior Secured Notes and hence would give the indenture trustee the right to exercise remedies pursuant to the indenture and the other financing documents.

State Regulation

Our power plants in California and Nevada, by virtue of being Qualifying Facilities that make only wholesale sales of electricity, are not subject to rate, financial and organizational regulations applicable to electric utilities in those states. The power plants each sell or will sell their electrical output under PPAs to electric utilities (Sierra Pacific Power Company, Nevada Power Company, Southern California Edison or SCPPA). All of the utilities except SCPPA are regulated by their respective state public utilities commissions. Sierra Pacific Power Company and Nevada Power Company, which merged and are doing business as NV Energy, are regulated by the PUCN. Southern California Edison is regulated by the CPUC.

Under Hawaii law, non-fossil generators are not subject to regulation as public utilities. Hawaii law provides that a geothermal power producer is to negotiate the rate for its output with the public utility purchaser. If such rate cannot be determined by mutual accord, the PUCH will set a just and reasonable rate. If a non-fossil generator in Hawaii is a Qualifying Facility, federal law applies to such Qualifying Facility and the utility is required to purchase the energy and capacity at its avoided cost. The rates for our power plant in Hawaii are established under a long-term PPA with HELCO.

Environmental Permits

U.S. environmental permitting regimes with respect to geothermal projects center upon several general areas of focus. The first involves land use approvals. These may take the form of Special Use Permits or Conditional Use Permits from local planning authorities or a series of development and utilization plan approvals and right of way approvals where the geothermal facility is entirely or partly on BLM or U.S. Forest Service lands. Certain federal approvals require a review of environmental impacts in conformance with the federal National Environmental Policy Act. In California, some local permit approvals require a similar review of environmental impacts under a state statute known as the California Environmental Quality Act. These federal and local land use approvals typically impose conditions and restrictions on the construction, scope and operation of geothermal projects.

The second category of permitting focuses on the installation and use of the geothermal wells themselves. Geothermal projects typically have three types of wells: (i) exploration wells designed to define and verify the geothermal resource, (ii) production wells to extract the hot geothermal liquids (also known as brine) for the power plant, and (iii) injection wells to inject the brine back into the subsurface resource. For example, in Nevada and on BLM lands, the well permits take the form of geothermal drilling permits for well installation. Approvals are also required to modify wells, including for use as production or injection wells. For all wells drilled in Nevada, a geothermal drilling permit must be obtained from the Nevada Division of Minerals. Those wells in Nevada to be used for injection will also require Underground Injection Control permits from the Nevada Division of Environmental Protection. Geothermal wells on private lands in California require drilling permits from the California Department of Conservation's DOGGR. The eventual designation of these installed wells as individual production or injection wells and the ultimate closure of any wells is also reviewed and approved by DOGGR pursuant to a DOGGR-approved Geothermal Injection Program.

A third category of permits involves the regulation of potential air emissions associated with the construction and operation of wells and power plants and surface water discharges associated with construction and operations activities. Generally, each well and plant requires a preconstruction air permit and storm water discharge permit before earthwork can commence. In addition, in some jurisdictions the wells that are to be used for production require and those used for injection may require air emissions permits to operate. Internal combustion engines and other air pollutant emissions sources at the projects may also require air emissions permits. For our projects, these permits are typically issued at the state or county level. Permits are also required to manage storm water during project construction and to manage drilling muds from well construction, as well as to manage certain discharges to surface impoundments, if any.

A fourth category of permits, that are required in both California and Nevada, includes ministerial permits such as building permits, hazardous materials storage and management permits, and pressure vessel operating permits. We are also required to obtain water rights permits in Nevada. In addition to permits, there are various regulatory plans and programs that are required, including risk management plans (federal and state programs) and hazardous materials management plans (in California).

In some cases our projects may also require permits, issued by the applicable federal agencies or authorized state agencies, regarding threatened or endangered species, permits to impact wetlands or other waters and notices of construction of structures which may have an impact on airspace. Environmental laws and regulations may change in the future, which may lead to increases in the time to receive such permits and associated costs of compliance.

As of the date of this report, all of the material environmental permits and approvals currently required for our operating power plants have been obtained. We are currently experiencing regulatory delays in obtaining various environmental permits and approvals required for projects in development and construction. These delays may lead to increases in the time and cost to complete these projects. Our operations are designed and conducted to comply with applicable environmental permit and approval requirements. Non-compliance with any such requirements could result in fines and penalties, and could also affect our ability to operate the affected project.

Environmental Laws and Regulations

Our facilities are subject to a number of environmental laws and regulations relating to development, construction and operation. In the U.S, these may include the Clean Air Act, the Clean Water Act, the Emergency Planning and Community Right-to-Know Act, the Endangered Species Act, the National Environmental Policy Act, the Resource Conservation and Recovery Act, and related state laws and regulations.

Our geothermal operations involve significant quantities of brine (substantially, all of which we reinject into the subsurface) and scale, both of which can contain materials (such as arsenic, antimony, lead, and naturally occurring radioactive materials) in concentrations that exceed regulatory limits used to define hazardous waste. We also use various substances, including isopentane and industrial lubricants that could become potential contaminants and are generally flammable. Hazardous materials are also used in our equipment manufacturing operations in Israel. As a result, our projects are subject to domestic and foreign federal, state and local statutory and regulatory requirements regarding the use, storage, fugitive emissions, and disposal of hazardous substances. The cost of investigation and removal or remediation activities associated with a spill or release of such materials could be significant.

Although we are not aware of any mismanagement of these materials, including any mismanagement prior to the acquisition of some of our power plants, that has materially impaired any of the power plant sites, any disposal or release of these materials onto the power plant sites, other than by means of permitted injection wells, could lead to contamination of the environment and result in material cleanup requirements or other responsive obligations under applicable environmental laws. We believe that at one time there may have been a gas station located on the Mammoth complex site, but because of significant surface disturbance and construction since that time further physical evaluation of the environmental condition of the former gas station site has been impractical. We believe that, given the subsequent surface disturbance and construction activity in the vicinity of the suspected location of the service station, it is likely that environmental contamination, if any, associated with the former facilities and any associated underground storage tanks would have already been encountered if they still existed.

Regulation of the Electric Utility Industry in our Foreign Countries of Operation

The following is a summary overview of certain aspects of the electric industry in the foreign countries in which we have an operating geothermal power plant. As such, it should not be considered a full statement of the laws in such countries or all of the issues pertaining thereto.

Guatemala. The General Electricity Law of 1996, Decree 93-96, created a wholesale electricity market in Guatemala and established a new regulatory framework for the electricity sector. The law created a new regulatory commission, the CNEE, and a new wholesale power market administrator, the AMM, for the regulation and administration of the sector. The AMM is a private not-for-profit entity. The CNEE functions as an independent agency under the Ministry of Energy and Mines and is in charge of regulating, supervising, and controlling compliance with the electricity law, overseeing the market and setting rates for transmission services, and distribution to medium and small customers. All distribution companies must supply electricity to such customers pursuant to long-term contracts with electricity generators. Large customers can contract directly with the distribution companies, electricity generators or power marketers, or buy energy in the spot market. Guatemala has approved a Law of Incentives for the Development of Renewable Energy Power plants, Decree 52-2003, in order to promote the development of renewable energy power plants in Guatemala. This law provides certain benefits to companies utilizing renewable energy, including a 10-year exemption from corporate income tax and VAT on imports and customs duties. On September 16, 2008, CNEE issued a resolution which approved the Technical Norms for the Connection, Operation, Control and Commercialization of the Renewable Distributed Generation and Self-producers Users with Exceeding Amounts of Energy. This Technical Norm was created to regulate all aspects of generation, connection, operation, control and commercialization of electric energy produced with renewable sources to promote and facilitate the installation of new generation plants, and to promote the connection of existing generation plants which have exceeding amounts of electric energy for commercialization. It is applicable to projects with a capacity of up to 5 MW.

Kenya. The electric power sector in Kenya is regulated by the Kenyan Energy Act. Among other things, the Kenyan Energy Act provides for the licensing of electricity power producers and public electricity suppliers or distributors. KPLC is the only licensed public electricity supplier and has a monopoly in the distribution of electricity in the country. The Kenyan Energy Act permits IPPs to install power generators and sell electricity to KPLC, which is owned by various private and government entities, and which currently purchases energy and capacity from other IPPs in addition to our Olkaria III complex. The electricity sector is regulated by the ERC which was created under the Kenyan Energy Act. KPLC's retail electricity rates are subject to approval by the ERC. The ERC has an expanded mandate to regulate not just the electric power sector but the entire energy sector in Kenya. Transmission of electricity is now undertaken by KETRACO while another company, GDC, is responsible for geothermal assessment, drilling of wells and sale of steam for electricity operations to IPPs and KenGen. Both KETRACO and GDC are wholly owned by the government of Kenya. Under the new national constitution enacted in August 2010, formulation of energy policy (including electricity) and energy regulation are functions of the national government. However, the constitution lists the planning and development of electricity and energy regulation as a function of the county governments (i.e. the regional or local level where an individual power plant is or is intended to be located).

ITEM 1A. RISK FACTORS

Because of the following factors, as well as other variables affecting our business, operating results or financial condition, past financial performance may not be a reliable indicator of future performance, and historical trends should not be used to anticipate results or trends in future periods.

Our financial performance depends on the successful operation of our geothermal power and REG plants, which is subject to various operational risks.

Our financial performance depends on the successful operation of our subsidiaries' geothermal and REG power plants. In connection with such operations, we derived approximately 63.2% of our total revenues for the year ended December 31, 2015 from the sale of electricity. The cost of operation and maintenance and the operating performance of our subsidiaries' geothermal power and REG plants may be adversely affected by a variety of factors, including some that are discussed elsewhere in these risk factors and the following:

- regular and unexpected maintenance and replacement expenditures;
- shutdowns due to the breakdown or failure of our equipment or the equipment of the transmission serving utility;
- labor disputes;
- the presence of hazardous materials on our power plant sites;
- continued availability of cooling water supply;
- catastrophic events such as fires, explosions, earthquakes, volcanic activity, landslides, floods, releases of hazardous materials, severe weather storms, or similar occurrences affecting our power plants or any of the power purchasers or other third parties providing services to our power plants; and
- the aging of power plants (which may reduce their availability and increase the cost of their maintenance).

Any of these events could significantly increase the expenses incurred by our power plants or reduce the overall generating capacity of our power plants and could significantly reduce or entirely eliminate the revenues generated by one or more of our power plants, which in turn would reduce our net income and could materially and adversely affect our business, financial condition, future results and cash flow.

As mentioned above, the aging of our power plants may reduce their availability and increase maintenance costs due to the need to repair or replace our equipment. For example, in 2015 we shutdown old equipment at the Ormesa complex. Such major maintenance activities impact both the capacity factor of the affected power plant and its operating costs

Our exploration, development, and operation of geothermal energy resources are subject to geological risks and uncertainties, which may result in decreased performance or increased costs for our power plants.

Our primary business involves the exploration, development, and operation of geothermal energy resources. These activities are subject to uncertainties that, in certain respects, are similar to those typically associated with oil and gas exploration, development, and exploitation, such as dry holes, uncontrolled releases, and pressure and temperature decline. Any of these uncertainties may increase our capital expenditures and our operating costs, or reduce the efficiency of our power plants. We may not find geothermal resources capable of supporting a commercially viable power plant at exploration sites where we have conducted tests, acquired land rights, and drilled test wells, which would adversely affect our development of geothermal power plants. Further, since the commencement of their operations, several of our power plants have experienced geothermal resource cooling uncontrolled flow and/or reservoir pressure decline in the normal course of operations. For example, some of Brady’s production wells have cooled significantly due to breakthrough from injection wells. Because geothermal reservoirs are complex geological structures, we can only estimate their geographic area and sustainable output. The viability of geothermal power plants depends on different factors directly related to the geothermal resource (such as the temperature, pressure, storage capacity, transmissivity, and recharge) as well as operational factors relating to the extraction or reinjection of geothermal fluids. For example, at our North Brawley power plant, instability of the sands and clay in the geothermal resource and variability in the chemical composition of the geothermal fluid have all combined to increase our capital expenditures for the plant, as well as our ongoing operating expenses, and have so far prevented the plant from operation at its intended design capacity. Another example is the Sarulla project, where we are both an equity investor and equipment supplier, which has experienced delays and budget cost overruns in the drilling program as a result of difficulties associated with the drilling of injection wells. Our geothermal energy power plants may also suffer an unexpected decline in the capacity of their respective geothermal wells and are exposed to a risk of geothermal reservoirs not being sufficient for sustained generation of the electrical power capacity desired over time.

Another aspect of geothermal operations is the management and stabilization of subsurface impacts caused by fluid injection pressures of production and injection fluids to mitigate subsidence. In the case of the geothermal resource supplying the Heber complex, pressure drawdown in the center of the well field has caused some localized ground subsidence, while pressure in the peripheral areas has caused localized ground inflation. Inflation and subsidence, if not controlled, can adversely affect farming operations and other infrastructure at or near the land surface. Potential costs, which cannot be estimated and may be significant, of failing to stabilize site pressures in the Heber complex area include repair and modification of gravity-based farm irrigation systems and municipal sewer piping and possible repair or replacement of a local road bridge spanning an irrigation canal.

Additionally, active geothermal areas, such as the areas in which our power plants are located, are subject to frequent low-level seismic disturbances, volcanic eruptions and lava flows. Serious seismic disturbances, volcanic eruptions and lava flows are possible and could result in damage to our power plants (or transmission lines used by customers who buy electricity from us) or equipment or degrade the quality of our geothermal resources to such an extent that we could not perform under the PPA for the affected power plant, which in turn could reduce our net income and materially and adversely affect our business, financial condition, future results and cash flow. If we suffer a serious seismic disturbance, volcanic eruptions and lava flows, our business interruption and property damage insurance may not be adequate to cover all losses sustained as a result thereof. In addition, insurance coverage may not continue to be available in the future in amounts adequate to insure against such seismic disturbances, volcanic eruptions and lava flows.

Furthermore, absent additional geologic/hydrologic studies, any increase in power generation from our geothermal power plants, failure to reinject the geothermal fluid or improper maintenance of the hydrological balance may affect the operational duration of the geothermal resource and cause it to decline in value over time, and may adversely affect our ability to generate power from the relevant geothermal power plant.

Reduced levels of recovered energy required for the operation of our REG power plants may result in decreased performance of such power plants.

Our REG power plants generate electricity from recovered energy or so-called “waste heat” that is generated as a residual by-product of gas turbine-driven compressor stations and a variety of industrial processes. Any interruption in the supply of the recovered energy source, such as a result of reduced gas flows in the pipelines or reduced level of operation at the compressor stations, or in the output levels of the various industrial processes, may cause an unexpected decline in the capacity and performance of our recovered energy power plants.

Our business development activities may not be successful and our projects under construction may not commence operation as scheduled.

We are in the process of developing and constructing a number of new power plants. Our success in developing a particular project is contingent upon, among other things, negotiation of satisfactory engineering and construction agreements and obtaining PPAs, receipt of required governmental permits, obtaining adequate financing, and the timely implementation and satisfactory completion of field development, testing and power plant construction commissioning. We may be unsuccessful in accomplishing any of these matters or doing so on a timely basis. Although we may attempt to minimize the financial risks attributable to the development of a project by securing a favorable PPA, obtaining all required governmental permits and approvals and arranging, in certain cases, adequate financing prior to the commencement of construction, the development of a power project may require us to incur significant expenses for preliminary engineering, permitting and legal and other expenses before we can determine whether a project is feasible, economically attractive or capable of being financed.

Currently, we have projects and prospects under exploration, development or construction in the U.S., Kenya, Chile, Guatemala, New Zealand, Honduras, Indonesia and Ethiopia, and we intend to pursue the expansion of some of our existing plants and the development of other new plants. Our completion of these facilities is subject to substantial risks, including:

Inability to secure a PPA;

Inability to secure the required financing;

cost increases and delays due to unanticipated shortages of adequate resources to execute the project such as, equipment, material and labor;

work stoppages resulting from force majeure event including riots, strikes and whether conditions;

inability to obtain permits, licenses and other regulatory approvals;

Failure to secure sufficient land positions for the wellfield, power plant and rights of way;

failure by key contractors and vendors to timely and properly perform, including where we use equipment manufactured by others;

failure by key suppliers to provide steam for electricity generation, including the Menengai project in Kenya

inability to secure or delays in securing the required transmission line and/or capacity;

adverse environmental and geological conditions (including inclement weather conditions);

adverse local business law; and

our attention to other projects, including those in the solar energy sector.

Any one of these could give rise to delays, cost overruns, the termination of the plant expansion, construction or development or the loss (total or partial) of our interest in the project under development, construction, or expansion.

We rely on power transmission facilities that we do not own or control.

We depend on transmission facilities owned and operated by others to deliver the power we sell from our power plants to our customers. If transmission is disrupted, or if the transmission capacity infrastructure is inadequate, our ability to sell and deliver power to our customers may be adversely impacted and we may either incur additional costs or forego revenues. In addition, lack of access to new transmission capacity may affect our ability to develop new projects. Existing congestion of transmission capacity, as well as expansion of transmission systems and competition from other developers seeking access to expanded systems, could also affect our performance.

We may be unable to obtain the financing we need to pursue our growth strategy and any future financing we receive may be less favorable to us than our current financing arrangements, either of which may adversely affect our ability to expand our operations.

Most of our geothermal power plants generally have been financed using leveraged financing structures, consisting of non-recourse or limited recourse debt obligations. Each of our projects under development or construction and those projects and businesses we may seek to acquire or construct will require substantial capital investment. Our continued access to capital with acceptable terms is necessary for the success of our growth strategy. Our attempts to obtain future financings may not be successful or on favorable terms**.**

Market conditions (including those described in the immediately preceding risk factor) and other factors may not permit future project and acquisition financings on terms similar to those our subsidiaries have previously received. Our ability to arrange for financing on a substantially non-recourse or limited recourse basis, and the costs of such financing, are dependent on numerous factors, including general economic conditions, conditions in the global capital and credit markets (as discussed above), investor confidence, the continued success of current power plants, the credit quality of the power plants being financed, the political situation in the country where the power plant is located, and the continued existence of tax and securities laws which are conducive to raising capital. If we are not able to obtain financing for our power plants on a substantially non-recourse or limited recourse basis, we may have to finance them using recourse capital such as direct equity investments or the incurrence of additional debt by us.

Also, in the absence of favorable financing options, we may decide not to build new plants or acquire facilities from third parties. Any of these alternatives could have a material adverse effect on our growth prospect.

We may also need additional financing to implement our new strategic plan. For example, our cash flow from operations and existing liquidity facilities may not be adequate to finance any acquisitions we may want to pursue or new technologies we may want to develop or acquire. Financing for acquisitions or technology-development activities may not be available on the non-recourse or limited recourse basis we have historically used for our business, or on other terms we find acceptable.

Our use of joint ventures may limit our flexibility with jointly owned investments.

We have sold minority equity interests in three of our consolidated subsidiaries, through which we hold a large number of our domestic geothermal power plants and recovered energy generation plants, to different third parties. We may continue in the future to develop and/or acquire and/or hold properties in joint ventures with other entities when circumstances warrant the use of these structures. Ownership of assets in joint ventures is subject to risks that may not be present with other methods of ownership, including:

we could experience an impasse on certain decisions because we do not have sole decision-making authority, which could require us to expend additional resources on resolving such impasses or potential disputes, including litigation or arbitration;

our joint venture partners could have investment goals that are not consistent with our investment objectives, including the timing, terms and strategies for any investments in the projects that are owned by the joint ventures, which could affect decisions about future capital expenditures, major operational expenditures and retirement of assets, among other things;

our ability to transfer our interest in a joint venture to a third party may be restricted and the market for our interest may be limited;

our joint venture partners may be structured differently than us for tax purposes, and this could impact our ability to fully take advantage of federal tax incentives available for renewable energy projects;

our joint venture partners might become bankrupt, fail to fund their share of required capital contributions or fail to fulfill their obligations as a joint venture partner, which may require us to infuse our own capital into the venture on behalf of the partner despite other competing uses for such capital; and

our joint venture partners may have competing interests in our markets and investments in companies that compete directly or indirectly with us that could create conflict of interest issues.

Our international operations expose us to risks related to the application of foreign laws, taxes, economic conditions, labor supply and relations, political conditions, and policies of foreign governments, any of which may adversely affect our business, financial condition, future results and cash flow.

We have substantial operations outside of the U.S., both in our Electricity segment and our Product segment. Our foreign operations are subject to regulation by various foreign governments and regulatory authorities and are subject to the application of foreign laws. Such foreign laws or regulations may not provide the same type of legal certainty and rights, in connection with our contractual relationships in such countries, as are afforded to our operations in the U.S., which may adversely affect our ability to receive revenues or enforce our rights in connection with our foreign operations. Furthermore, existing laws or regulations may be amended or repealed, and new laws or regulations may be enacted or issued. In addition, the laws and regulations of some countries may limit our ability to hold a majority interest in some of the power plants that we may develop or acquire, thus limiting our ability to control the development, construction and operation of such power plants, or our ability to import our products into such countries. Our foreign operations are also subject to significant political, economic and financial risks, which vary by country, and include:

- changes in government policies or personnel;
- changes in general economic conditions;
- restrictions on currency transfer or convertibility;
- changes in labor relations;
- political instability and civil unrest;
- changes in the local electricity and/or geothermal markets;
- breach or repudiation of important contractual undertakings by governmental entities; and
- expropriation and confiscation of assets and facilities.

In particular, in regards to our Electricity segment, in Guatemala the electricity sector was partially privatized, and it is currently unclear whether further privatization will occur in the future. Such developments may affect our Amatitlan and Zunil power plants if, for example, they result in changes to the prevailing tariff regime or in the identity and creditworthiness of our power purchasers. In Kenya, any break-up and potential privatization of KPLC may adversely affect our Olkaria III complex. Although we generally obtain political risk insurance in connection with our foreign power plants, such political risk insurance does not mitigate all of the above-mentioned risks. In addition, insurance proceeds received pursuant to our political risk insurance policies, where applicable, may not be adequate to cover all losses sustained as a result of any covered risks and may at times be pledged in favor of the power plant lenders as collateral. Also, insurance may not be available in the future with the scope of coverage and in amounts of coverage adequate to insure against such risks and disturbances. In regards to our Product segment, since we primarily engage in sales in those markets where there is a geothermal reservoir, any such change might adversely affect geothermal developers in those markets and, subsequently, the ability of such developers to purchase our products. Any or all of these changes could materially adversely affect our business, financial condition, future results and cash flow.

Our foreign power plants and foreign manufacturing operations expose us to risks related to fluctuations in currency rates, which may reduce our profits from such power plants and operations.

Risks attributable to fluctuations in currency exchange rates can arise when any of our foreign subsidiaries borrow funds or incur operating or other expenses in one type of currency but receive revenues in another. In such cases, an adverse change in exchange rates can reduce such subsidiary’s ability to meet its debt service obligations, reduce the amount of cash and income we receive from such foreign subsidiary or increase such subsidiary's overall expenses. In addition, the imposition by foreign governments of restrictions on the transfer of foreign currency abroad, or restrictions on the conversion of local currency into foreign currency, would have an adverse effect on the operations of our foreign power plants and foreign manufacturing operations, and may limit or diminish the amount of cash and income that we receive from such foreign power plants and operations.

A significant portion of our electricity revenues is attributed to payments made by power purchasers under PPAs. The failure of any such power purchaser to perform its obligations under the relevant PPA or the loss of a PPA due to a default would reduce our net income and could materially and adversely affect our business, financial condition, future results and cash flow.

A significant portion of our revenues is attributed to our electricity revenues derived from power purchasers under the relevant PPAs. There is a risk that any one or more of the power purchasers may not fulfill their respective payment obligations under their PPAs. If any of the power purchasers fails to meet its payment obligations under its PPAs, it could materially and adversely affect our business, financial condition, future results and cash flow.

Seasonal variations may cause significant fluctuations in our cash flows, which may cause the market price of our common stock to fall in certain periods.

Our results of operations are subject to seasonal variations. This is primarily because some of our domestic power plants receive higher capacity payments under the relevant PPAs during the summer months, and due to the generally higher time-of-use energy factor during the summer months. Some of our other power plants may experience reduced generation during warm periods due to the lower heat differential between the geothermal fluid and the ambient surroundings. Such seasonal variations could materially and adversely affect our business, financial condition, future results and cash flow. If our operating results fall below the public's or analysts' expectations in some future period or periods, the market price of our common stock will likely fall in such period or periods.

Pursuant to the terms of some of our PPAs with investor-owned electric utilities and public-owned electric utilities in states that have renewable portfolio standards, the failure to supply the contracted capacity and energy thereunder may result in the imposition of penalties.

Pursuant to the terms of certain of our PPAs, we may be required to make payments to the relevant power purchaser under certain conditions, such as shortfall in delivery of renewable energy and energy credits, and not meeting certain performance threshold requirements, as defined in the relevant PPA. The amount of payment required is dependent upon the level of shortfall in delivery or performance requirements and is recorded in the period the shortfall occurs. In addition, if we do not meet certain minimum performance requirements, the capacity of the relevant power plant may be permanently reduced.

Any or all of these considerations could materially and adversely affect our business, financial condition, future results and cash flow.

The SRAC for our power purchasers may decline, which would reduce our power plant revenues and could materially and adversely affect our business, financial condition, future results and cash flow.

Under a number of the PPAs for our power plants in California, the price that Southern California Edison pays is based upon its SRAC, which are the incremental costs that it would have incurred had it generated the relevant electricity itself or purchased such electricity from others. Under settlement agreements between Southern California Edison and a number of power generators in California that are Qualifying Facilities, including our subsidiaries, the energy price component payable by Southern California Edison was fixed through April 2012, but since then is based on Southern California Edison’s SRAC, as determined by the CPUC. The SRAC may vary substantially on a monthly basis, and are expected to be based primarily on natural gas prices for gas delivered to California as well as other factors. The levels of SRAC prices paid by Southern California Edison may decline following the expiration date of the settlement agreements, which in turn would reduce our power plant revenues derived from Southern California Edison under our PPAs and could materially and adversely affect our business, financial condition, future results and cash flow.

Under the terms of a global settlement approved by CPUC (Global Settlement) SRAC for our Ormesa complex, Heber 2 and Mammoth G2 PPAs are tied to a formula with energy market heat rates. The Global Settlement further provides that after July 1, 2015 if the term of any of the PPAs we have for these power plants expires, would have no obligation to purchase power from any of these plants that has a generating capacity in excess of 20 MW, which would apply to the PPAs for our Ormesa complex (53 MW contract capacity) and Heber 2 power plant (37 MW contract capacity) with Southern California Edison. Our Mammoth G2 plant (10.5 MW contract capacity) will be entitled to a new standard offer PPA, with SRAC pricing and capacity payments as determined from time to time by the CPUC. The joint parties to the Global Settlement agreed that the utilities can go to FERC to obtain a waiver of the mandatory purchase obligation under PURPA for Qualifying Facilities above 20 MW and FERC has granted such waiver for these California utilities.

If any of our domestic power plants loses its current Qualifying Facility status under PURPA, or if amendments to PURPA are enacted that substantially reduce the benefits currently afforded to Qualifying Facilities, our domestic operations could be adversely affected.

Most of our domestic power plants are Qualifying Facilities pursuant to PURPA, which largely exempts the power plants from the FPA, and certain state and local laws and regulations regarding rates and financial and organizational requirements for electric utilities.

If any of our domestic power plants were to lose its Qualifying Facility status, such power plant could become subject to the full scope of the FPA and applicable state regulation. The application of the FPA and other applicable state regulation to our domestic power plants could require our operations to comply with an increasingly complex regulatory regime that may be costly and greatly reduce our operational flexibility.

If a domestic power plant were to lose its Qualifying Facility status, it would become a public utility under the FPA, and the rates charged by such power plant pursuant to its PPAs would be subject to the review and approval of FERC. FERC, upon such review, may determine that the rates currently set forth in such PPAs are not appropriate and may set rates that are lower than the rates currently charged. In addition, FERC may require that the affected domestic power plant refund amounts previously paid by the relevant power purchaser to such power plant. Even if a power plant does not lose its Qualifying Facility status, pursuant to regulations issued by FERC for Qualifying Facility power plants above 20 MW, if a power plant’s PPA is terminated or otherwise expires, and the subsequent sales are not made pursuant to a state’s implementation of PURPA, that power plant will become subject to FERC’s ratemaking jurisdiction under the FPA. Moreover, a loss of Qualifying Facility status also could permit the power purchaser, pursuant to the terms of the particular PPA, to cease taking and paying for electricity from the relevant power plant or, consistent with FERC precedent, to seek refunds of past amounts paid. This could cause the loss of some or all of our revenues payable pursuant to the related PPAs, result in significant liability for refunds of past amounts paid, or otherwise impair the value of our power plants. If a power purchaser were to cease taking and paying for electricity or seek to obtain refunds of past amounts paid, there can be no assurance that the costs incurred in connection with the power plant could be recovered through sales to other purchasers or that we would have sufficient funds to make such payments. In addition, the loss of Qualifying Facility status would be an event of default under the financing arrangements currently in place for some of our power plants, which would enable the lenders to exercise their remedies and enforce the liens on the relevant power plant.

Pursuant to the Energy Policy Act of 2005, FERC also has the authority to prospectively lift the mandatory obligation of a utility under PURPA to offer to purchase the electricity from a Qualifying Facility if the utility operates in a workably competitive market. Existing PPAs between a Qualifying Facility and a utility are not affected. If, in addition to the California utilities’ waiver of the mandatory purchase obligation for QF projects that exceed 20 MW described in the risk factor above entitled "The SRAC for our power purchasers may decline, which would reduce our power plant revenues and could materially and adversely affect our business, financial condition, future results and cash flow.", the utilities in the other regions in which our domestic power plants operate were to be relieved of the mandatory purchase obligation, they would not be required to purchase energy from the power plant in the region under Federal law upon termination of the existing PPA or with respect to new power plants, which could materially and adversely affect our business, financial condition, future results and cash flow. Moreover, FERC has the authority to modify its regulations relating to the utility’s mandatory purchase obligation under PURPA, which could result in the reduction in the purchase obligation of California and other utilities to a level below 20 MW, or the elimination of the purchase obligation. If that were to occur it could materially and adversely affect our business, financial condition, future results and cash flow.

The reduction or elimination of government incentives could adversely affect our business, financial condition, future results and cash flows.

Construction and operation of our geothermal power plants and recovered energy-based power plants has benefited, and may benefit in the future, from public policies and government incentives that support renewable energy and enhance the economic feasibility of these projects in regions and countries where we operate. Such policies and incentives include PTCs and ITCs, accelerated depreciation tax benefits, renewable portfolio standards, carbon trading mechanisms, rebates, and mandated feed-in-tariffs, and may include similar or other incentives to end users, distributors, system integrators and manufacturers of geothermal, solar and other power products. Some of these measures have been implemented at the federal level, while others have been implemented by different states within the U.S. or countries outside the U.S. where we operate.

The availability and continuation of these public policies and government incentives have a significant effect on the economics and viability of our development program and continued construction of new geothermal, recovered energy-based and Solar PV power plants. Any changes to such public policies, or any reduction in or elimination or expiration of such government incentives could affect us in different ways. For example, any reduction in, termination or expiration of renewable portfolio standards may result in less demand for generation from our geothermal and recovered energy-based, power plants. Any reductions in, termination or expiration of other government incentives could reduce the economic viability of, and cause us to reduce, the construction of new geothermal, recovered energy-based, and Solar PV power plants. Similarly, any such changes that affect the geothermal energy industry in a manner that is different from other sources of renewable energy, such as wind or solar, may put us at a competitive disadvantage compared to businesses engaged in the development, construction and operation of renewable power projects using such other resources. Any of the foregoing outcomes could have a material adverse effect on our business, financial condition, future results, and cash flows.

Our financial performance could be adversely affected by changes in the legal and regulatory environment affecting our power plants.

All of our power plants are subject to extensive regulation, and therefore changes in applicable laws or regulations, or interpretations of those laws and regulations, could result in increased compliance costs, the need for additional capital expenditures or the reduction of certain benefits currently available to our power plants. The structure of domestic and foreign federal, state and local energy regulation currently is, and may continue to be, subject to challenges, modifications, the imposition of additional regulatory requirements, and restructuring proposals. We or our power purchasers may not be able to obtain all regulatory approvals that may be required in the future, or any necessary modifications to existing regulatory approvals, or maintain all required regulatory approvals. In addition, the cost of operation and maintenance and the operating performance of geothermal power plants may be adversely affected by changes in certain laws and regulations, including tax laws.

Any changes to applicable laws and regulations could significantly increase the regulatory-related compliance and other expenses incurred by the power plants and could significantly reduce or entirely eliminate the revenues generated by one or more of the power plants, which in turn would reduce our net income and could materially and adversely affect our business, financial condition, future results and cash flow.

The costs of compliance with environmental laws and of obtaining and maintaining environmental permits and governmental approvals required for construction and/or operation may increase in the future and these costs (as well as any fines or penalties that may be imposed upon us in the event of any non-compliance with such laws or regulations) could materially and adversely affect our business, financial condition, future results and cash flow.

Environmental laws, ordinances and regulations affecting us can be subject to change and such change could result in increased compliance costs, the need for additional capital expenditures, or otherwise adversely affect us. In addition, our power plants are required to comply with numerous domestic and foreign, federal, regional, state and local statutory and regulatory environmental standards and to maintain numerous environmental permits and governmental approvals required for construction and/or operation. We may not be able to renew, maintain or obtain all environmental permits and governmental approvals required for the continued operation or further development of the power plants. We have not yet obtained certain permits and government approvals required for the completion and successful operation of power plants under construction or enhancement. Our failure to renew, maintain or obtain required permits or governmental approvals, including the permits and approvals necessary for operating power plants under construction or enhancement, could cause our operations to be limited or suspended. Finally, some of the environmental permits and governmental approvals that have been issued to the power plants contain conditions and restrictions, including restrictions or limits on emissions and discharges of pollutants and contaminants, or may have limited terms. If we fail to satisfy these conditions or comply with these restrictions, or with any statutory or regulatory environmental standards, we may become subject to regulatory enforcement action and the operation of the power plants could be adversely affected or be subject to fines, penalties or additional costs.

We could be exposed to significant liability for violations of hazardous substances laws because of the use or presence of such substances at our power plants.

Our power plants are subject to numerous domestic and foreign federal, regional, state and local statutory and regulatory standards relating to the use, storage and disposal of hazardous substances. We use butane, pentane, industrial lubricants, and other substances at our power plants which are or could become classified as hazardous substances. If any hazardous substances are found to have been released into the environment at or by the power plants in concentrations that exceed regulatory limits, we could become liable for the investigation and removal of those substances, regardless of their source and time of release. If we fail to comply with these laws, ordinances or regulations (or any change thereto), we could be subject to civil or criminal liability, the imposition of liens or fines, and large expenditures to bring the power plants into compliance. Furthermore, in the U.S., we can be held liable for the cleanup of releases of hazardous substances at other locations where we arranged for disposal of those substances, even if we did not cause the release at that location. The cost of any remediation activities in connection with a spill or other release of such substances could be significant.

We believe that at one time there may have been a gas station located on the Mammoth complex site, but because of significant surface disturbance and construction since that time, further physical evaluation of the environmental condition of the former gas station site has been impractical. There may be soil or groundwater contamination and related potential liabilities of which we are unaware related to this site, which may be significant and could materially and adversely affect our business, financial condition, future results and cash flow.

We may decide not to implement, or may not be successful in implementing, one or more elements of our new multi-year strategic plan, and the plan as implemented may not achieve its goal to enhance shareholder value through long-term growth of the Company

We recently adopted a multi-year strategic plan to:

- Expand our geographical base;
- Expand into new technologies, such as energy storage and solar PV electric power generation both in large "utility scale" projects and smaller C&I projects for commercial, industrial, governmental, educational and other institutional customers; and
- Expand our customer base.

There are uncertainties and risks associated with the plan, both as to implementation and outcome. Implementation of the plan may be affected by a number of factors, including that:

- we are still developing some elements of the plan and evaluating how and when some elements of the plan will be implemented,
- we may decide to change, or not implement, one or more elements of the plan over time, and
- we may not be successful in implementing one or more elements of the plan, in each case for a number of reasons.

For example, we will face significant challenges and risks expanding into new technologies (or expanding our geographical or customer base for those new technologies), including:

- Our ability to compete with the large number of other companies pursuing similar business opportunities in energy storage and solar PV power generation, many of which already have established businesses in these areas and/or have greater financial, strategic, technological or other resources than we have.
- Our ability to obtain financing on terms we consider acceptable, or at all, which we may need, for example, to obtain any technology, personnel, intellectual property, or to acquire one or more existing businesses as a platform for our expansion, or to fund internal research and development, for energy storage and solar PV electric power generation products and services.

- Our ability to provide energy storage or solar electric power generation products or services that keep pace with rapidly changing technology, customer preferences, equipment costs, market conditions and other factors that will impact these markets.
- Our ability to devote the amount of management time and other resources required to implement this plan, consistent with continuing to grow our core geothermal and recovered energy businesses; and
- Our ability to recruit appropriate employees

Expanding our geothermal and recovered energy businesses to new customers and geographical areas will have many of the same risks and uncertainties as those outlined above. These or other factors could mean that we decide to change or even abandon, or are otherwise unable to implement, one or more elements of the plan.

Implementing the plan will involve various costs, including, among other things:

- opportunity costs associated with foregone alternative uses of our resources;
- various expense items that will impact our current financial results; and
- perhaps asset revaluations if, for example, businesses or other assets acquired for new energy storage or solar PV power generation products or services suffer impairment charges, as a result of rapidly changing technology, market conditions or otherwise.

These costs may not be recovered, in whole or in part, if one or more elements of the plan are not successfully implemented. These costs, or the failure to implement successfully one or more elements of the plan, could adversely affect the reputation of our group of companies and could materially and adversely affect our business, financial condition, future results and cash flow and the price at which our common stock is traded.

Apart from the risks associated with implementing the plan, the plan itself will expose us to other risks and uncertainties once implemented. For example, expanding our customer base may expose us to different credit profile customers than our current customers. Another example, expanding our geographic base will subject us to risks associated with doing business in new foreign countries, and expanding into new technologies will expose us to risks associated with those products and services. Some of these risks may be similar to those we now face as described in other risks factors; others may differ or be unknown to us now. The success of the plan, once implemented, will depend, among other things, on our ability to manage these risks effectively.

The trading price of our common stock could decline if securities or industry analysts or our investors disagree with our strategic plan or the way we implement it, either as a result of the factors outlined above or for other reasons.

Accordingly, there is no assurance that the plan will enhance shareholder value through long-term growth of the Company to the extent currently anticipated by our management or at all.

We may not be able to successfully integrate companies which we may acquire in the future, which could materially and adversely affect our business, financial condition, future results and cash flow.

Our strategy is to continue to expand in the future, including through acquisitions. Integrating acquisitions is often costly, and we may not be able to successfully integrate our acquired companies with our existing operations without substantial costs, delays or other adverse operational or financial consequences. Integrating our acquired companies involves a number of risks that could materially and adversely affect our business, including:

- failure of the acquired companies to achieve the results we expect;
- inability to retain key personnel of the acquired companies;
- risks associated with unanticipated events or liabilities; and

the difficulty of establishing and maintaining uniform standards, controls, procedures and policies, including accounting controls and procedures.

If any of our acquired companies suffers customer dissatisfaction or performance problems, this could adversely affect the reputation of our group of companies and could materially and adversely affect our business, financial condition, future results and cash flow.

The power generation industry is characterized by intense competition, and we encounter competition from electric utilities, other power producers, and power marketers that could materially and adversely affect our business, financial condition, future results and cash flow.

The power generation industry is characterized by intense competition from electric utilities, other power producers and power marketers. In recent years, there has been increasing competition in the sale of electricity, in part due to excess capacity in a number of U.S. markets and an emphasis on short-term or “spot” markets, and competition has contributed to a reduction in electricity prices. For the most part, we expect that power purchasers interested in long-term arrangements will engage in “competitive bid” solicitations to satisfy new capacity demands. This competition could adversely affect our ability to obtain PPAs and the price paid for electricity by the relevant power purchasers. There is also increasing competition between electric utilities. This competition has put pressure on electric utilities to lower their costs, including the cost of purchased electricity, and increasing competition in the future will put further pressure on power purchasers to reduce the prices at which they purchase electricity from us.

We face competition from other companies engaged in the solar energy sector.

The solar power market is intensely competitive and rapidly evolving. We compete with many companies that have longer operating histories in this sector, larger customer bases, and greater brand recognition, as well as, in some cases, significantly greater financial and marketing resources than us. In some cases, these competitors are vertically integrated in the solar energy sector, manufacturing Solar PV, silicon wafers, and other related products for the solar industry, which may give them an advantage in developing, constructing, owning and operating solar power projects. Our limited experience in the Solar PV sector may affect our ability to successfully develop, construct, finance, and operate Solar PV power projects**.**

The existence of a prolonged force majeure event or a forced outage affecting a power plant or the transmission system of the IID could reduce our net income and materially and adversely affect our business, financial condition, future results and cash flow.

The operation of our subsidiaries' geothermal power plants is subject to a variety of risks discussed elsewhere in these risk factors, including events such as fires, explosions, earthquakes, landslides, floods, severe storms, volcanic eruptions, lava flow or other similar events. If a power plant experiences an occurrence resulting in a force majeure event, although our subsidiary that owns that power plant would be excused from its obligations under the relevant PPA the relevant power purchaser may not be required to make any capacity and/or energy payments with respect to the affected power plant or plant so long as the force majeure event continues and, pursuant to certain of our PPAs, will have the right to prematurely terminate the PPA. Additionally, to the extent that a forced outage has occurred, the relevant power purchaser may not be required to make any capacity and/or energy payments to the affected power plant, and if as a result the power plant fails to attain certain performance requirements under certain of our PPAs, the purchaser may have the right to permanently reduce the contract capacity (and correspondingly, the amount of capacity payments due pursuant to such agreements in the future), seek refunds of certain past capacity payments, and/or prematurely terminate the PPA. As a consequence, we may not receive any net revenues from the affected power plant other than the proceeds from any business interruption insurance that applies to the force majeure event or forced outage after the relevant waiting period, and may incur significant liabilities in respect of past amounts required to be refunded.

In addition, if the transmission system of the IID experiences a force majeure event or a forced outage which prevents it from transmitting the electricity from the Heber complex, the Ormesa complex or the North Brawley power plant to the relevant power purchaser, the relevant power purchaser would not be required to make energy payments for such non-delivered electricity and may not be required to make any capacity payments with respect to the affected power plant so long as such force majeure event or forced outage continues. The impact of such force majeure would depend on the duration thereof, with longer outages resulting in greater loss of revenues. In the event of any such force majeure event, our business, financial condition, future results and cash flows could be materially and adversely affected.

Some of our leases will terminate if we do not extract geothermal resources in "commercial quantities", thus requiring us to enter into new leases or secure rights to alternate geothermal resources, none of which may be available on terms as favorable to us as any such terminated lease, if at all.

Most of our geothermal resource leases are for a fixed primary term, and then continue for so long as geothermal resources are extracted in "commercial quantities" or pursuant to other terms of extension. The land covered by some of our leases is undeveloped and has not yet produced geothermal resources in commercial quantities. Leases that cover land which remains undeveloped and does not produce, or does not continue to produce, geothermal resources in commercial quantities and leases that we allow to expire, will terminate. In the event that a lease is terminated and we determine that we will need that lease once the applicable power plant is operating, we would need to enter into one or more new leases with the owner(s) of the premises that are the subject of the terminated lease(s) in order to develop geothermal resources from, or inject geothermal resources into, such premises or secure rights to alternate geothermal resources or lands suitable for injection. We may not be able to do this or may not be able to do so without incurring increased costs, which could materially and adversely affect our business, financial condition, future results and cash flow.

Our BLM leases may be terminated if we fail to comply with any of the provisions of the Geothermal Steam Act or if we fail to comply with the terms or stipulations of such leases, which could materially and adversely affect our business, financial condition, future results and cash flow.

Pursuant to the terms of our BLM leases, we are required to conduct our operations on BLM-leased land in a workmanlike manner and in accordance with all applicable laws and BLM directives and to take all mitigating actions required by the BLM to protect the surface of and the environment surrounding the relevant land. Additionally, certain BLM leases contain additional requirements, some of which relate to the mitigation or avoidance of disturbance of any antiquities, cultural values or threatened or endangered plants or animals. In the event of a default under any BLM lease, or the failure to comply with such requirements, or any non-compliance with any of the provisions of the Geothermal Steam Act or regulations issued thereunder, the BLM may, 30 days after notice of default is provided to our relevant project subsidiary, suspend our operations until the requested action is taken or terminate the lease, either of which could materially and adversely affect our business, financial condition, future results and cash flow.

Some of our leases (or subleases) could terminate if the lessor (or sublessor) under any such lease (or sublease) defaults on any debt secured by the relevant property, thus terminating our rights to access the underlying geothermal resources at that location.

The fee interest in the land which is the subject of some of our leases (or subleases) may currently be or may become subject to encumbrances securing loans from third-party lenders to the lessor (or sublessor). Our rights as lessee (or sublessee) under such leases (or subleases) are or may be subject and subordinate to the rights of any such lender. Accordingly, a default by the lessor (or sublessor) under any such loan could result in a foreclosure on the underlying fee interest in the property and thereby terminate our leasehold interest and result in the shutdown of the power plant located on the relevant property and/or terminate our right of access to the underlying geothermal resources required for our operations.

In addition, a default by a sublessor under its lease with the owner of the property that is the subject of our sublease could result in the termination of such lease and thereby terminate our sublease interest and our right to access the underlying geothermal resources required for our operations.

Current and future urbanizing activities and related residential, commercial, and industrial developments may encroach on or limit geothermal or Solar PV activities in the areas of our power plants, thereby affecting our ability to utilize access, inject and/or transport geothermal resources on or underneath the affected surface areas.

Current and future urbanizing activities and related residential, commercial and industrial development may encroach on or limit geothermal activities in the areas of our power plants or construction and operation of Solar PV facilities, thereby affecting our ability to utilize, access, inject, and/or transport geothermal resources on or underneath the affected surface areas or build Solar PV facilities, which require large areas of relatively flat land. In particular, the Heber power plants rely on an area, which we refer to as the Heber Known Geothermal Resource Area, or Heber KGRA, for the geothermal resource necessary to generate electricity at the Heber power plants. Imperial County has adopted a “specific plan area” that covers the Heber KGRA, which we refer to as the “Heber Specific Plan Area”. The Heber Specific Plan Area allows commercial, residential, industrial and other employment oriented development in a mixed-use orientation, which currently includes geothermal uses. Several of the landowners from whom we hold geothermal leases have expressed an interest in developing their land for residential, commercial, industrial or other surface uses in accordance with the parameters of the Heber Specific Plan Area. Currently, Imperial County’s Heber Specific Plan Area is coordinated with the cities of El Centro and Calexico. There has been ongoing underlying interest since the early 1990s to incorporate the community of Heber. While any incorporation process would likely take several years, if Heber were to be incorporated, the City of Heber could replace Imperial County as the governing land use authority, which, depending on its policies, could have a significant effect on land use and availability of geothermal resources.

Current and future development proposals within Imperial County and the City of Calexico, applications for annexations to the City of Calexico, and plans to expand public infrastructure may affect surface areas within the Heber KGRA, thereby limiting our ability to utilize, access, inject and/or transport the geothermal resource on or underneath the affected surface area that is necessary for the operation of our Heber power plants, which could adversely affect our operations and reduce our revenues.

Current construction works and urban developments in the vicinity of our Steamboat complex of power plants in Nevada may also affect future permitting for geothermal operations relating to those power plants. Such works and developments include plans for the construction of a new casino hotel and other commercial or industrial developments on land in the vicinity of our Steamboat complex.

We depend on key personnel for the success of our business.

In general, our success depends to a significant extent on the performance of our senior management, particularly the continued service of our key employees. Our success also depends on our ability to identify, hire and retain other qualified and experienced key personnel. Although to date we have been successful in identifying, hiring and retaining the services of senior management, we face risks associated with our ability to locate or employ on acceptable terms qualified replacements for our senior management or key employees if their services were no longer available, and with the inherent difficulties and uncertainties of transitioning the Company under the leadership of new management. Our inability to successfully identify, hire and retain any key employee could materially harm our business, financial condition, future results and cash flow.

Our power plants have generally been financed through a combination of our corporate funds and limited or non-recourse project finance debt and lease financing. If our project subsidiaries default on their obligations under such limited or non-recourse debt or lease financing, we may be required to make certain payments to the relevant debt holders, and if the collateral supporting such leveraged financing structures is foreclosed upon we may lose certain of our power plants.

Our power plants have generally been financed using a combination of our corporate funds and limited or non-recourse project finance debt or lease financing. Limited recourse project finance debt refers to our additional agreement, as part of the financing of a power plant, to provide limited financial support for the power plant subsidiary in the form of limited guarantees, indemnities, capital contributions and agreements to pay certain debt service deficiencies. Non-recourse project finance debt or lease financing refers to financing arrangements that are repaid solely from the power plant’s revenues and are secured by the power plant’s physical assets, major contracts, cash accounts and, in many cases, our ownership interest in the project subsidiary. If our project subsidiaries default on their obligations under the relevant debt documents, creditors of a limited recourse project financing will have direct recourse to us, to the extent of our limited recourse obligations, which may require us to use distributions received by us from other power plants, as well as other sources of cash available to us, in order to satisfy such obligations. In addition, if our project subsidiaries default on their obligations under the relevant debt documents (or a default under such debt documents arises as a result of a cross-default to the debt documents of some of our other power plants) and the creditors foreclose on the relevant collateral, we may lose our ownership interest in the relevant project subsidiary or our project subsidiary owning the power plant would only retain an interest in the physical assets, if any, remaining after all debts and obligations were paid in full.

Changes in costs and technology may significantly impact our business by making our power plants and products less competitive.

A basic premise of our business model is that generating baseload power at geothermal power plants achieves economies of scale and produces electricity at a competitive price. However, traditional coal-fired systems and gas-fired systems may under certain economic conditions produce electricity at lower average prices than our geothermal plants. In addition, there are other technologies that can produce electricity, most notably fossil fuel power systems, hydroelectric systems, fuel cells, microturbines, windmills, Solar PV cells and Solar PV systems. Some of these alternative technologies currently produce electricity at a higher average price than our geothermal plants, however research and development activities are ongoing to seek improvements in such alternate technologies and their cost of producing electricity is gradually declining. It is possible that advances will further reduce the cost of alternate methods of power generation to a level that is equal to or below that of most geothermal power generation technologies. If this were to happen, the competitive advantage of our power plants may be significantly impaired.

Our expectations regarding the market potential for the development of recovered energy-based power generation may not materialize, and as a result we may not derive any significant revenues from this line of business.

Demand for our recovered energy-based power generation units may not materialize or grow at the levels that we expect. We currently face competition in this market from manufacturers of conventional steam turbines and may face competition from other related technologies in the future. If this market does not materialize at the levels that we expect, such failure may materially and adversely affect our business, financial condition, future results and cash flow.

Our intellectual property rights may not be adequate to protect our business.

Our intellectual property rights may not be adequate to protect our business. While we occasionally file patent applications, patents may not be issued on the basis of such applications or, if patents are issued, they may not be sufficiently broad to protect our technology. In addition, any patents issued to us or for which we have use rights may be challenged, invalidated or circumvented.

In order to safeguard our unpatented proprietary know-how, trade secrets and technology, we rely primarily upon trade secret protection and non-disclosure provisions in agreements with employees and others having access to confidential information. These measures may not adequately protect us from disclosure or misappropriation of our proprietary information.

Even if we adequately protect our intellectual property rights, litigation may be necessary to enforce these rights, which could result in substantial costs to us and a substantial diversion of management attention. Also, while we have attempted to ensure that our technology and the operation of our business do not infringe other parties’ patents and proprietary rights, our competitors or other parties may assert that certain aspects of our business or technology may be covered by patents held by them. Infringement or other intellectual property claims, regardless of merit or ultimate outcome, can be expensive and time-consuming and can divert management’s attention from our core business.

Threats of terrorism and catastrophic events that could result from terrorism, cyber-attacks, or individuals and/or groups attempting to disrupt our business, or the businesses of third parties, may impact our operations in unpredictable ways and could adversely affect our business, financial condition, future results and cash flow.

We are subject to the potentially adverse operating and financial effects of terrorist acts and threats, as well as cyber-attacks, including, among others, malware, viruses and attachments to e-mails, and other disruptive activities of individuals or groups. Our generation and transmission facilities, information technology systems and other infrastructure facilities and systems and physical assets, could be directly or indirectly affected by such activities. Terrorist acts or other similar events could harm our business by limiting our ability to generate or transmit power and by delaying the development and construction of new generating facilities and capital improvements to existing facilities. These events, and governmental actions in response, could result in a material decrease in revenues and significant additional costs to repair and insure our assets, and could adversely affect operations by contributing to the disruption of supplies and markets for geothermal and recovered energy. Such events could also impair our ability to raise capital by contributing to financial instability and lower economic activity.

We operate in a highly regulated industry that requires the continued operation of sophisticated information technology systems and network infrastructure. Despite our implementation of security measures, all of our technology systems (and any programs or data stored thereon or therein) are vulnerable to security breaches, failures, data leakage or unauthorized access due to such activities. Those breaches and events may result from acts of our employees, contractors or third parties. If our technology systems were to fail or be breached and we were unable to recover in a timely way, we would be unable to fulfill critical business functions, and sensitive confidential and other data could be compromised, which could adversely affect our business, financial condition, future results and cash flow.

The implementation of security guidelines and measures and maintenance of insurance, to the extent available, addressing such activities could increase costs. These types of events could adversely affect our business, financial condition, future results and cash flow. In addition such events could require significant management attention and resources and could adversely affect our reputation among customers and the public.

A disruption of transmission or the transmission infrastructure facilities of third parties could negatively impact our business. Because generation and transmission systems are part of an interconnected system, we face the risk of possible loss of business due to a disruption caused by the impact of an event on the interconnected system within our systems or within a neighboring system. Any such disruption could adversely affect our business, financial condition, future results and cash flow.

Possible fluctuations in the cost of construction, raw materials, commodities and drilling may materially and adversely affect our business, financial condition, future results, and cash flow.

Our manufacturing operations are dependent on the supply of various raw materials, including primarily steel and aluminum, commodities and industrial equipment components that we use. We currently obtain all such raw materials, commodities and equipment at prevailing market prices. We are not dependent on any one supplier and do not have any long-term agreements with any of our suppliers. Future cost increases of such raw materials, commodities and equipment, to the extent not otherwise passed along to our customers, could adversely affect our profit margins.

Conditions in and around Israel, where the majority of our senior management and our main production and manufacturing facilities are located, may adversely affect our operations and may limit our ability to produce and sell our products or manage our power plants.

The majority of our senior management our main production and manufacturing facilities are located in Israel. As such, political, economic and security conditions in Israel directly affect our operations.

Since the establishment of the State of Israel in 1948, a number of armed conflicts have taken place between Israel and its Arab neighbors, and the continued state of hostility, varying in degree and intensity, has led to security and economic problems for Israel.

Negotiations between Israel and representatives of the Palestinian Authority in an effort to resolve the state of conflict have been sporadic and have failed to result in peace. The establishment in 2006 of a government in the Gaza territory by representatives of the Hamas militant group has created additional unrest and uncertainty in the region. In each of December 2008, November 2012 and July 2014, Israel engaged in an armed conflict with Hamas, each of which involved additional missile strikes from the Gaza Strip into Israel and disrupted most day-to-day civilian activity in the proximity of the border with the Gaza Strip. Our production facilities in Israel are located approximately 26 miles from the border with the Gaza Strip.

The political instability and civil unrest in the Middle East and North Africa (including the ongoing civil war in Syria) as well as the increased tension between Iran and Israel have raised new concerns regarding security in the region and the potential for armed conflict or other hostilities involving Israel. We could be adversely affected by any such hostilities, the interruption or curtailment of trade between Israel and its trading partners, or a significant downturn in the economic or financial condition of Israel. In addition, the sale of products manufactured in Israel may be adversely affected in certain countries by restrictive laws, policies or practices directed toward Israel or companies having operations in Israel.

In addition, some of our employees in Israel are subject to being called upon to perform military service in Israel, and their absence may have an adverse effect upon our operations. Generally, unless exempt, male adult citizens of Israel under the age of 41 are obligated to perform up to 36 days of military reserve duty annually. Additionally, all such citizens are subject to being called to active duty at any time under emergency circumstances.

These events and conditions could disrupt our operations in Israel, which could materially harm our business, financial condition, future results, and cash flow.

We are a holding company and our revenues depend substantially on the performance of our subsidiaries and the power plants they operate, most of which are subject to restrictions and taxation on dividends and distributions.

We are a holding company whose primary assets are our ownership of the equity interests in our subsidiaries. We conduct no other business and, as a result, we depend entirely upon our subsidiaries' earnings and cash flow.

The agreements pursuant to which most of our subsidiaries have incurred debt restrict the ability of these subsidiaries to pay dividends, make distributions or otherwise transfer funds to us prior to the satisfaction of other obligations, including the payment of operating expenses, debt service and replenishment or maintenance of cash reserves. In the case of some of our power plants that are owned jointly with other partners, there may be certain additional restrictions on dividend distributions pursuant to our agreements with those partners. Further, if we elect to receive distributions of earnings from our foreign operations, we may incur U.S. taxes on account of such distributions, net of any available foreign tax credits. In all of the foreign countries where our existing power plants are located, dividend payments to us are also subject to withholding taxes. Each of the events described above may reduce or eliminate the aggregate amount of revenues we can receive from our subsidiaries.

The Israeli Tax Ruling we obtained in connection with our acquisition of Ormat Industries imposes conditions that may limit our flexibility in operating our business and our ability to enter into certain corporate transactions.

The Israel Tax Ruling we obtained in connection with the acquisition of Ormat Industries imposes a number of conditions that limit our flexibility in operating our business and in engaging in certain corporate transactions. These conditions include, among others, that until the end of 2016, each of Bronicki and FIMI may not sell their shares of our common stock, except in certain limited circumstances and in connection with these sale limitations, we cannot engage in a sale of the Company (through a merger or otherwise), conduct certain private placements of our common stock or public offerings of our common stock that will result in a decrease of their stockholdings to less than 51% of their holdings immediately following the closing of the share exchange. Additionally, until the end of 2018, we agreed to maintain (and, to the extent that our operations expand, likewise expand) the production activities we currently carry out in Israel. Under certain circumstances, these conditions may not allow us the flexibility that we need to operate our business and may prevent us from taking advantage of strategic opportunities that would benefit our business and our stockholders.

As a result of the share exchange, a substantial percentage of our shares is held by a small group of stockholders whose interests may conflict with the interests of our other stockholders.

As of February 23, 2016, Bronicki and FIMI beneficially own, collectively, approximately 22.67% of our outstanding common stock. Bronicki and FIMI are parties to a shareholder rights agreement that, among other things, includes joint voting and other arrangements that affect us and our subsidiaries. As a result of these stockholders' beneficial ownership of our outstanding common stock, and taking into consideration the shareholders rights agreement between them, they could exert significant influence on the election of our directors and decisions on matters submitted to a vote of our shareholders, including mergers, consolidations and the sale of all or substantially all of our assets. This concentration of ownership of our shares could delay or prevent proxy contests, mergers, tender offers, or other purchases of our shares that might otherwise give our stockholders the opportunity to realize a premium over the then-prevailing market price for our shares. This concentration of ownership may also adversely affect our stock price.

The price of our common stock may fluctuate substantially and your investment may decline in value.

The market price of our common stock may be highly volatile and may fluctuate substantially due to many factors, including:

- actual or anticipated fluctuations in our results of operations including as a result of seasonal variations in our Electricity segment-based revenues or variations from year-to-year in our Product segment-based revenues;
- variance in our financial performance from the expectations of market analysts;
- conditions and trends in the end markets we serve, and changes in the estimation of the size and growth rate of these markets;
- announcements of significant contracts by us or our competitors;
- changes in our pricing policies or the pricing policies of our competitors;
- restatements of historical financial results and changes in financial forecasts;
- loss of one or more of our significant customers;

- legislation;
- changes in market valuation or earnings of our competitors;
- the trading volume of our common stock;
- the trading of our common stock on multiple trading markets, which takes place in different currencies and at different times; and
- general economic conditions.

In addition, the stock market in general, and the NYSE and the market for energy companies in particular, have experienced extreme price and volume fluctuations that have often been unrelated or disproportionate to the operating performance of particular companies affected. These broad market and industry factors may materially harm the market price of our common stock, regardless of our operating performance. In the past, following periods of volatility in the market price of a company's securities, securities class-action litigation has often been instituted against that company. Such litigation, if instituted against us, could result in substantial costs and a diversion of management's attention and resources, which could materially harm our business, financial condition, future results and cash flow.

Future sales of common stock by some of our existing stockholders could cause our stock price to decline.

As of the date of this report, FIMI holds approximately 14.91% of our outstanding common stock, Bronicki holds approximately 7.76% of our outstanding common stock, and some of our directors, officers and employees also hold shares of our outstanding common stock. Sales of such shares in the public market, as well as shares we may issue upon exercise of outstanding options, could cause the market price of our common stock to decline. We are party to several agreements with FIMI and Bronicki, including (1) a registration rights agreement whereby FIMI and Bronicki may require us to register our common stock held by them with the SEC or to include our common stock held by them in an offering and sale by us, and (2) voting neutralization agreements that, among other things, restrict their ability to sell our common stock held by them.

Provisions in our charter documents and Delaware law may delay, prevent or deter an acquisition of us, which could adversely affect the value of our common stock.

Our restated certificate of incorporation and our bylaws contain provisions that could make it harder for a third party to acquire us without the consent of our Board of Directors. These provisions include procedural requirements relating to stockholder meetings and stockholder proposals that could make stockholder actions more difficult. Our Board of Directors is classified into three classes of directors serving staggered, three-year terms and directors may be removed only for cause. Any vacancy on the Board of Directors may be filled only by the vote of the majority of directors then in office. Delaware law also imposes some restrictions on mergers and other business combinations between us and any holder of 15% or more of our outstanding common stock.

Regulations related to conflict minerals may force us to incur additional expenses and may damage our relationship with certain customers.

On August 22, 2012, the SEC adopted requirements regarding mandatory disclosure for companies regarding their use of "conflict minerals" (including tantalum, tin, tungsten and gold) in their products. In general, while we do not directly purchase or use any of these “conflict minerals” as raw materials in the products we manufacture or as part of our manufacturing processes, we will need to examine whether such minerals are contained in the products supplied to us by third parties and, if so, whether such minerals originate from the Democratic Republic of Congo or adjoining countries. If we utilize any of these minerals and they are necessary to the production or functionality of any of our products or products we are contracted to manufacture, we will need to conduct specified due diligence activities and file with the SEC a report disclosing, among others, whether such minerals originate from the Democratic Republic of Congo or adjoining countries. The implementation of these SEC rules could adversely affect the sourcing, availability and pricing of minerals used in the manufacture of certain components incorporated in our products. In addition, we expect to incur additional costs to comply with the disclosure requirements, including costs related to determining the source of any of the relevant minerals and metals used in our products, and possibly additional expenses related to any changes to our products we may decide are advisable based upon our due diligence findings. Since our supply chain is complex, we may not be able to sufficiently verify the origins for these minerals and metals used in our products through the diligence procedures that we implement, which may harm our reputation. In such event, we may also face difficulties in satisfying customers who require that all of the components of our products are certified as conflict mineral free.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

We currently lease corporate offices at 6225 Neil Road, Reno, Nevada 89511-1136. We also occupy an approximately 807,000 square foot office and manufacturing facility located in the Industrial Park of Yavne, Israel, which we lease from the Israel Land Administration. See Item 13 — "Certain Relationships and Related Transactions". We also lease small offices in each of the countries in which we operate.

We believe that our current facilities will be adequate for our operations as currently conducted.

Each of our power plants is located on property leased or owned by us or one of our subsidiaries, or is a property that is subject to a concession agreement.

Information and descriptions of our plants and properties are included in Item 1 — "Business", of this annual report.

ITEM 3. LEGAL PROCEEDINGS

There were no material developments in any legal proceedings to which the Company is a party during the fiscal year 2015, other than as described below.

Jon Olson and Hilary Wilt, together with Puna Pono Alliance, an unincorporated association, filed a complaint on February 17, 2015, in the Third Circuit Court for the State of Hawaii, requesting declaratory and injunctive relief requiring that PGV comply with an ordinance that the plaintiffs allege will prohibit PGV from engaging in night drilling operations at its KS-16 well site. On May 17, 2015, the original complaint was amended to add the county of Hawaii and the State of Hawaii Department of Land and Natural Resources as defendants to the case. PGV believes that the allegations have no merit, and will continue to defend itself vigorously.

On July 8, 2014, Global Community Monitor, LiUNA, and two residents of Bishop, California filed a complaint in the U.S. District Court for the Eastern District of California, alleging that Mammoth Pacific, L.P., the Company and Ormat Nevada are operating three geothermal generating plants in Mammoth Lakes, California (MP-1, MP-II and PLES-I) in violation of the federal Clean Air Act and Great Basin Unified Air Pollution Control District rules. On

June 26, 2015, in response to a motion by the defendants, the court dismissed all but one of the plantiffs' causes of action. On October 14, 2015, the court denied the defendants' motion to dismiss the plaintiffs' sole remaining claim. Discovery has commenced. The Company believes that the allegations of the lawsuit have no merit, and will continue to defend itself vigorously.

On April 5, 2012, the International Brotherhood of Electrical Workers Local 1260 ("Union") filed a petition with the NLRB seeking to organize the operations and maintenance employees at the Puna project. PGV lost the union election by a slim margin in May 2012. The election results and the NLRB's decision to require PGV to negotiate with the Union were appealed to the U.S. Court of Appeals for the Ninth Circuit, but were remanded back to the NLRB after the Supreme Court of the U.S.' decision in NLRB v. Noel Canning, 573 U.S., 134 S.Ct. 2550 (2014). On November 26, 2014, the NLRB found that certification of the Union should be issued. In January 2015, the parties submitted a briefing to the NLRB as to whether summary judgment was appropriate. On June 26, 2015, the Board rejected PGV's arguments and ordered PGV to recognize the Union. On June 30, 2015, PGV appealed the NLRB decision to the U.S. Court of Appeals for the DC Circuit. The NLRB has put on hold its December 8, 2015 request for a hearing to bring unfair labor practice allegations before an administrative law judge in view of ongoing settlement discussions. The Company believes that there are valid defenses under law.

In January 2014, Ormat learned that two former employees filed a "qui tam" complaint seeking damages, penalties and other relief, alleging that the Company and certain of its subsidiaries (collectively, the "Ormat Parties"), submitted fraudulent applications and certifications to obtain grants for the Puna and North Brawley projects. The U.S. Department of Justice declined to intervene. The complaint, which is pending before the U.S. District Court for the District of Nevada, is in the discovery and early depositions stage. On July 7, 2015, the Court issued a protective order stipulating limitations against the qui tam relators for the benefit of the Ormat Parties, to ensure the protection of confidentiality for sensitive Ormat Parties' documents. On December 15, 2015, the defendants filed a motion for summary judgment with the court, which they expect to brief in March, 2016. The Ormat Parties believe that the allegations of the lawsuit have no merit, and will continue to defend themselves vigorously.

In addition, from time to time, the Company is named as a party to various other lawsuits, claims and other legal and regulatory proceedings that arise in the ordinary course of our business. These actions typically seek, among other things, compensation for alleged personal injury, breach of contract, property damage, punitive damages, civil penalties or other losses, or injunctive or declaratory relief. With respect to such lawsuits, claims and proceedings, the Company accrues reserves when a loss is probable and the amount of such loss can be reasonably estimated. It is the opinion of the Company’s management that the outcome of these proceedings, individually and collectively, will not be material to the Company’s consolidated financial statements as a whole.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

PART II

ITEM 5. *MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES*

Our common stock is traded on the NYSE under the symbol "ORA" effective since November 11, 2004. Prior to November 11, 2004, there was no public market for our stock. Effective on February 10, 2015, our common stock also began trading on the TASE.

As of February 23, 2016, there were 22 record holders of the Company's common stock. On February 23, 2016, our stock's closing price as reported on the NYSE was $36.75 per share.

Dividends

We have adopted a dividend policy pursuant to which we currently expect to distribute at least 20% of our annual profits available for distribution by way of quarterly dividends. In determining whether there are profits available for distribution, our Board of Directors will take into account our business plan and current and expected obligations, and no distribution will be made that in the judgment of our Board of Directors would prevent us from meeting such business plan or obligations.

Notwithstanding this policy, dividends will be paid only when, as and if approved by our Board of Directors out of funds legally available therefor. The actual amount and timing of dividend payments will depend upon our financial condition, results of operations, business prospects and such other matters as the Board may deem relevant from time to time. Even if profits are available for the payment of dividends, the Board of Directors could determine that such profits should be retained for an extended period of time, used for working capital purposes, expansion or acquisition of businesses or any other appropriate purpose. As a holding company, we are dependent upon the earnings and cash flow of our subsidiaries in order to fund any dividend distributions and, as a result, we may not be able to pay dividends in accordance with our policy. Our Board of Directors may, from time to time, examine our dividend policy and may, in its absolute discretion, change such policy. In addition to the required Board of Directors' approval for the payment of dividends, the Company can declare as dividends no more than 35% of annual net income as dividends due to restrictions related to its third-party debt (see Note 12 to our consolidated financial statements set forth in Item 8 of this annual report).

We have declared the following dividends over the past two years:

Date Declared	Dividend Amount per Share	Record Date	Payment Date
November 5, 2014	$ 0.05	November 20, 2014	December 4, 2014
February 24, 2015	$ 0.08	March 16, 2015	March 27, 2015
May 6, 2015	$ 0.06	May 19, 2015	May 27, 2015
August 3, 2015	$ 0.06	August 18, 2015	September 2, 2015
November 3, 2015	$ 0.06	November 18, 2015	December 2, 2015
February 23, 2016	$ 0.31	March 15, 2016	March 29, 2016

High/Low Stock Prices

The following table sets forth the high and low sales prices of our common stock for the years ended December 31, 2014 and 2015, and from January 1, 2016 until February 23, 2016:

	First Quarter 2014	Second Quarter 2014	Third Quarter 2014	Fourth Quarter 2014	First Quarter 2015	Second Quarter 2015	Third Quarter 2015	Fourth Quarter 2015	January 1 to February 23, 2016
High	$ 30	$ 30	$ 29	$ 29	$ 38	$ 40	$ 41	$ 38	$ 37
Low:	$ 24	$ 26	$ 25	$ 26	$ 26	$ 36	$ 34	$ 34	$ 33

Stock Performance Graph

The following performance graph represents the cumulative total shareholder return for the period November 11, 2004 (the date upon which trading of the Company’s common stock commenced) through December 31, 2015 for our common stock, compared to the Standard and Poor’s Composite 500 Index, and two peer groups.

Comparison of Cumulative Returns for the Period November 11, 2004 through December 31, 2015

	11/11/2004	End 2004	End 2005	End 2006	End 2007	End 2008	End 2009	End 2010	End 2011	End 2012	End 2013	End 2014	End 2015

Ormat Technologies Inc	0%	9%	74%	145%	267%	112%	152%	97%	20%	29%	81%	81%	143%
Standard & Poor's Composite 500 Index	0%	8%	11%	26%	31%	-20%	-1%	12%	12%	27%	65%	84%	82%
^NEX -Wilder Hill new Energy Global	0%	9%	30%	74%	174%	7%	50%	28%	-23%	-28%	12%	11%	7%
IPP Peers*	0%	22%	26%	79%	79%	77%	107%	119%	131%	165%	187%	222%	111%
Renewable Peers**	0%	41%	19%	63%	204%	20%	45%	-25%	-22%	-30%	-42%	-23%	17%

* IPP Peers are The AES Corporation, NRG Energy Inc., Calpine Corporation and Covanta Holding Corp.

** Renewable Energy (Renewable) Peers are Acciona S.A. and U.S. Geothermal Inc.

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The above Stock Performance Graph shall not be deemed to be soliciting material or to be filed with the SEC under the Securities Act and the Exchange Act except to the extent that the Company specifically requests that such information be treated as soliciting material or specifically incorporates it by reference into a filing under the Securities Act or the Exchange Act.

Equity Compensation Plan Information

For information on our equity compensation plan, refer to Item 12 — “Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters”.

ITEM 6. ***SELECTED FINANCIAL DATA***

The following table sets forth our selected consolidated financial data for the years ended and at the dates indicated. We have derived the selected consolidated financial data for the years ended December 31, 2015, 2014 and 2013 and as of December 31, 2015 and 2014 from our audited consolidated financial statements set forth in Item 8 of this annual report. We have derived the selected consolidated financial data for the years ended December 31, 2012 and 2011 and as of December 31, 2013, 2012 and 2011 from our audited consolidated financial statements not included herein.

The information set forth below should be read in conjunction with Item 7 — "Management's Discussion and Analysis of Financial Condition and Results of Operations" and our consolidated financial statements, including the notes thereto, set forth in Item 8 of this annual report.

	Year Ended December 31,				
	2015	**2014**	**2013**	**2012**	**2011**
	(Dollars in thousands, except per share data)				
Statements of Operations Data:					
Revenues:					
Electricity	$375,920	$382,301	$329,747	$314,894	$312,296
Product	218,724	177,223	203,492	186,879	113,160
Total revenues	594,644	559,524	533,239	501,773	425,456
Cost of revenues:					
Electricity	242,612	246,630	232,874	237,415	235,609
Product	133,753	109,143	140,547	135,346	76,072
Total cost of revenues	376,365	355,773	373,421	372,761	311,681
Gross margin	218,279	203,751	159,818	129,012	113,775
Operating expenses:					
Research and development expenses	1,780	783	4,965	6,108	8,801
Selling and marketing expenses	16,077	15,425	24,613	15,718	16,053
General and administrative expenses	34,782	28,614	29,188	28,066	27,366
Impairment charge	—	—	—	236,377	—
Write-off of unsuccessful exploration activities	1,579	15,439	4,094	2,639	—
Operating Income (loss)	164,061	143,490	96,958	(159,896)	61,555
Other income (expense):					
Interest income	297	312	1,332	1,201	1,427
Interest expense, net	(72,577)	(84,654)	(73,776)	(64,069)	(69,459)
Foreign currency translation and transaction gains (losses)	(1,622)	(5,839)	5,085	242	(1,350)
Income attributable to sale of tax benefits	25,431	24,143	19,945	10,127	11,474
Gain from sale of property, plant and equipment	—	7,628	—	—	—
Gain from extinguishment of liability	—	—	—	—	—
Other non-operating income (expense), net	(1,991)	756	1,592	590	671
Income (loss) from continuing operations, before income taxes and equity in income (losses) of investees	113,599	85,836	51,136	(211,805)	4,318

Income tax (provision) benefit	15,258	(27,608)	(13,552)	(1,827)	(48,240)
Equity in losses of investees, net	(5,508)	(3,213)	(250)	(2,522)	(959)
Income (loss) from continuing operations	123,349	55,015	37,334	(216,154)	(44,881)
Discontinued operations:					
Income from discontinued operations (including gain on disposal of $0, $0, $3,646, $0, and $0, respectively)	—	—	5,311	4,811	2,452
Income tax provision	—	—	(614)	(1,264)	(295)
Total income from discontinued operations	—	—	4,697	3,547	2,157
Net Income (loss)	123,349	55,015	42,031	(212,607)	(42,724)
Net income attributable to noncontrolling interest	(3,776)	(833)	(793)	(414)	(332)
Net income (loss) attributable to the Company's stockholders	$119,573	$54,182	$41,238	$(213,021)	$(43,056)

	Year Ended December 31,				
	2015	2014	2013	2012	2011
	(Dollars in thousands, except per share data)				
Earnings (loss) per share attributable to the Company's stockholders:					
Basic:					
Income (loss) from continuing operations	$2.46	$1.19	$0.81	$(4.77)	$(1.00)
Discontinued operations	—	—	0.10	0.08	0.05
Net income (loss)	$2.46	$1.19	$0.91	$(4.69)	$(0.95)
Diluted:					
Income from continuing operations	$2.43	$1.18	$0.81	$(4.77)	$(1.00)
Discontinued operations	—	—	0.10	0.08	0.05
Net Income (loss)	$2.43	$1.18	$0.91	$(4.69)	$(0.95)
Weighted average number of shares used in computation of earnings (loss) per share attributable to the Company's stockholders:					
Basic	48,562	45,508	45,440	45,431	45,431
Diluted	49,187	45,859	45,475	45,431	45,431
Dividend per share declared	$0.26	$0.21	$0.08	$0.08	$0.13
Balance Sheet Data (at end of year):					
Cash and cash equivalents	$185,919	40,230	57,354	66,628	99,886
Working capital	186,635	68,121	103,001	64,100	98,415
Property, plant and equipment, net (including construction-in process)	1,808,170	1,734,359	1,741,163	1,649,014	1,889,083
Total assets	2,293,044	2,121,556	2,159,433	2,087,523	2,314,718
Long-term debt (including current portion)	920,465	1,001,410	1,077,857	1,030,928	1,025,010
Equity	1,083,874	786,746	745,111	695,607	906,644

ITEM 7. *MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS*

You should read the following discussion and analysis of our results of operations, financial condition and liquidity in conjunction with our consolidated financial statements and the related notes. Some of the information contained in this discussion and analysis or set forth elsewhere in this annual report including information with respect to our plans and strategies for our business, statements regarding the industry outlook, our expectations regarding the future performance of our business, and the other non-historical statements contained herein are forward-looking statements. See "Cautionary Note Regarding Forward-Looking Statements." You should also review Item 1A — "Risk Factors" for a discussion of important factors that could cause actual results to differ materially from the results described herein or implied by such forward-looking statements.

General

Overview

We are a leading vertically integrated company engaged primarily in the geothermal and recovered energy power business. With the objective of becoming a leading global provider of renewable energy, we are focused on several key initiatives, under our new strategic plan, as described in this annual report.

We design, develop, build, sell, own, and operate clean, environmentally friendly geothermal and recovered energy-based power plants, usually using equipment that we design and manufacture.

Our geothermal power plants include both power plants that we have built and power plants that we have acquired, while we have built all of our recovered energy-based plants. We currently conduct our business activities in two business segments:

The Electricity segment — in this segment, we develop, build, own and operate geothermal and recovered energy-based power plants in the U.S. and geothermal power plants in other countries around the world, and sell the electricity they generate; and

The Product segment — in this segment we design, manufacture and sell equipment for geothermal and recovered energy-based electricity generation, remote power units and other power generating units and provide services relating to the engineering, procurement, construction, operation and maintenance of geothermal and recovered energy-based power plants.

Both our Electricity segment and Product segment operations are conducted in the U.S. and the rest of the world. Our current generating portfolio includes geothermal plants in the U.S., Guatemala, and Kenya, as well as REG plants in the U.S.

For the year ended December 31, 2015, our total revenues increased by 6.3% (from $559.5 million to $594.6 million) over the previous year.

For the year ended December 31, 2015, Electricity segment revenues were $375.9 million, compared to $382.3 million for the year ended December 31, 2014, a decrease of 1.7%, mainly as a result of approximately $30.0 million reduction related to the impact of lower oil and natural gas prices as well as lower revenues in the Puna power plant having lower generation as a result of a hurricane. Product segment revenues for the year ended December 31, 2015 were $218.7 million, compared to $177.2 million for the year ended December 31, 2014, an increase of 23.4%.

During the years ended December 31, 2015 and 2014, our consolidated power plants generated 4,835,109 MWh and 4,450,910 MWh, respectively, an increase of 8.6%

For the year ended December 31, 2015, our Electricity segment generated approximately 63.2% of our total revenues (68.3% in 2014), while our Product segment generated approximately 36.8% of our total revenues (31.7% in 2014).

For the year ended December 31, 2015, approximately 86% of our Electricity segment revenues were from PPAs with fixed energy rates which are not affected by fluctuations in energy commodity prices. We have variable price PPAs in California and Hawaii, which provide for payments based on the local utilities' avoided cost, which is the incremental cost that the power purchaser avoids by not having to generate such electrical energy itself or purchase it from others, as follows:

- the energy rates under the PPAs in California for each of the Ormesa complex, Heber 2 power plant in the Heber complex and the G2 power plant in the Mammoth complex change primarily based on fluctuations in natural gas prices; and

- the prices paid for the electricity pursuant to the 25 MW PPA for the Puna complex in Hawaii change primarily due to variations in the price of oil.

We reduced our economic exposure to fluctuations in the price of oil until December 31, 2014 and in the price of natural gas until March 31, 2015, from June 1, 2015 until December 31, 2015 and recently from February 3, 2016 until December 29, 2016, by entering into derivatives transactions. For the year ended December 31, 2015, we recorded a net gain of $1.2 million in electricity revenues related to these transactions.

To comply with obligations under their respective PPAs, certain of our project subsidiaries are structured as special purpose, bankruptcy remote entities and their assets and liabilities are ring-fenced. Such assets are not generally available to pay our debt other than debt at the respective project subsidiary level. However, these project subsidiaries are allowed to pay dividends and make distributions of cash flows generated by their assets to us subject in some cases to restrictions in debt instruments, as described below.

Electricity segment revenues are also subject to seasonal variations and can be affected by higher-than-average ambient temperatures, as described below under "Seasonality". In addition, the revenues we report in our financial statements may show more variation due to our increased use of derivatives in connection with our variable price PPAs and the accounting principles associated with our use of those derivatives.

Revenues attributable to our Product segment are based on the sale of equipment, EPC contracts and the provision of various services to our customers. Product segment revenues may vary from period to period because of the timing of our receipt of purchase orders and the progress of our equipment manufacturing and execution of the relevant project.

Our management assesses the performance of our two operating segments of operation differently. In the case of our Electricity segment, when making decisions about potential acquisitions or the development of new projects, management typically focuses on the internal rate of return of the relevant investment, technical and geological matters and other business considerations. Management evaluates our operating power plants based on revenues, expenses, and EBITDA, and our projects that are under development based on costs attributable to each such project. Management evaluates the performance of our Product segment based on the timely delivery of our products, performance quality of our products, revenues and expenses and costs actually incurred to complete customer orders compared to the costs originally budgeted for such orders.

Trends and Uncertainties

The geothermal industry in the U.S. has historically experienced significant growth followed by a consolidation of owners and operators of geothermal power plants. Since 2001, there has been increased demand for energy generated from geothermal resources in the U.S. as costs for electricity generated from geothermal resources have become more competitive. Much of this is attributable to legislative and regulatory requirements and incentives, such as state renewable portfolio standards and federal tax credits. The ARRA further encourages the use of geothermal energy through PTCs or ITCs as well as cash grants (which are discussed in more detail in the section entitled “Government Grants and Tax Benefits” below) although the ARRA benefits will expire absent new legislation that extends the deadline. In response, the geothermal industry in the U.S. has seen a wave of new entrants and, over the last several years, consolidation involving smaller developers. We believe that the future demand for energy generated from geothermal and other renewable resources in the U.S. will be driven by further commitment and implementation of renewable portfolio standards as well as the introduction of additional tax incentives and greenhouse gas initiatives. The trends that from time to time impact our operations are subject to market cycles.

Although other trends, factors and uncertainties may impact our operations and financial condition, including many that we do not or cannot foresee, we believe that our results of operations and financial condition for the foreseeable future will be primarily affected by the following trends, factors and uncertainties:

We expect to continue to generate the majority of our revenues from our Electricity segment through the sale of electricity from our power plants. All of our current revenues from the sale of electricity are derived from payments under long-term PPAs related to fully-contracted power plants. We also intend to continue to pursue opportunities, as they arise in our recovered energy business, in the Solar PV sector, energy storage and in other forms of clean energy.

We have adopted a new strategic plan for growth of our company, in terms of geographic scope, customer base, and technology platforms covered by our product and service offerings, with a view to increasing net income from operations. Under this plan, we will continue to focus on organic growth and increasing operational efficiency of our existing business lines. In addition, we are actively pursuing acquisition opportunities, both in our existing business lines and the solar power generation and energy storage businesses targeted as part of the plan. We will face a number of challenges and uncertainties in implementing this plan, and we may revise elements of the plan in response to market conditions or other factors as we move forward with the plan.

The continued awareness of climate change may result in significant changes in the business and regulatory environments, which may create business opportunities for us. For example, in June 2013, President Barack Obama announced a new national climate action plan, directing the EPA to complete new carbon dioxide pollution standards for both new and existing power plants. The EPA published rules relating to carbon pollution standards for certain existing, new, modified and reconstructed power plants on October 23, 2015. Under the Clean Power Plan that applies to certain existing power plants, states are to prepare –plans to meet the EPA’s goal of cutting carbon emission from the power sector by 32% below 2005 levels nationwide by 2030. On February 9, 2016, the Supreme Court of the U.S. stayed the Clean Power Plan pending resolution of legal challenges to the plan. According to the White House , even as legal challenges to the plan proceed, the EPA has indicated it will work with states that choose to continue plan development and implementation and will prepare the tools those states will need to meet the requirements under the Clean Power Plan. In addition, several states and regions are already addressing legislation to reduce GHG emissions. For example, California’s state climate change law, AB 32, which was signed into law in September 2006, regulates most sources of GHG emissions and aims to reduce GHG emissions to 1990 levels by 2020. On October 20, 2011, the CARB adopted cap-and-trade regulations to reduce California’s GHG emissions under AB 32. On April 29, 2015, California’s Governor Brown issued an Executive Order setting an interim target of 40% below 1990 levels by 2030. In addition to California, twenty U.S. states have set GHG emissions reduction targets. Regional initiatives are also being developed to reduce GHG emissions and develop trading systems for renewable energy credits. In the U.S., approximately 40 states have adopted RPS, renewable portfolio goals, or similar laws requiring or encouraging electric utilities in such states to generate or buy a certain percentage of their electricity from renewable energy sources or recovered heat sources. On April 12, 2011, SBX1-2 was signed into law, and increased California’s RPS to 33% by December 31, 2020. In October 2015, California’s Governor signed SB 350. Under the new bill, California’s RPS have been increased to 50% by 2030. In June 2015, Hawaii’s Governor signed a bill that sets the state’s renewable energy goal at 100% by 2045. These bills may facilitate additional sales and trading options when negotiating PPAs and selling electricity from our existing power plants and any new power plants we may develop or acquire in these states.

Following the historical agreement signed at the COP21 UN Climate Change Conference held in Paris, as well as other initiatives such as the American Business Act on Climate Pledge, the Mission Innovation initiative and, the Breakthrough Energy Coalition, we believe that our global operations may benefit from increasing efforts by governments and businesses around the world to flight climate change and move towards a low carbon, resilient and sustainable future. These developments and governmental plans may create opportunities for us to acquire and develop geothermal power generation facilities internationally, as well as additional opportunities for our Product segment.

In June 2013, the Nevada state legislature passed three bills that were signed by Nevada's Governor and were expected to support additional renewable energy development in the state. SB No. 123 required the retirement or elimination of not less than 800 MW of coal-fired electric generating capacity on or before December 31, 2019 and the construction or acquisition of, or contracting for, 550 MW of anticipated natural gas resources and 350 MW of electric generating capacity from renewable energy facilities. The provisions of SB 123 have been fulfilled in part and indefinitely suspended in part:

- Three new Solar PV projects totaling 215 MW and acquisitions by Nevada Power of 3 existing natural-gas-fired facilities generating about 496 MW of electric power fulfilled most of the SB 123 mandate.

- Approximately 135 MW of the SB 123 mandate has not been fulfilled, and the requirement to do so has been indefinitely suspended by new legislation adopted by the Nevada legislature in 2015. That legislation, AB 498, suspended the SB 123 mandate with respect to the portion of the mandate that has not been fulfilled.

Final regulations have been adopted to implement other 2013 Nevada legislation related to RPS in Nevada and the related quantification and qualification of different types of portfolio energy credits that may be used by Nevada utilities to satisfy RPS requirements. These regulations (when fully effective) are expected to align Nevada's RPS with current RPS standards in other states in the regional WREGIS market, such as by:

- eliminating a 2.4 multiplier that previously applied to new solar PV distributed generation,

- phasing out (by 2025) Nevada's inclusion of energy efficiency credits which have previously counted for up to 25% of Nevada's RPS and phasing out recognition of the related PECs for purposes of Nevada's RPS, and

- diminishing the allowance for station usage PECs for geothermal projects under the Nevada RPS.

On September 26, 2014, Governor Brown of California signed into law AB-2363, which requires the CPUC to adopt, by December 31, 2015, a methodology for determining the costs of integrating eligible renewable energy resources. As of the date of this report no methodology has been adopted.

Outside of the U.S., in November 2012, the U.S., Brunei, and Indonesia formed the Asia-Pacific comprehensive partnership and President Obama announced the allocation of $6.0 billion for green energy development in Asia. Also, on June 30, 2013, President Obama announced the "Power Africa" initiative pursuant to which the U.S. will invest $7.0 billion in Sub-Saharan Africa over the following five years, with the aim of doubling access to power. Sub-Saharan Africa includes three countries (Ethiopia, Kenya and Tanzania) that have large geothermal potential as well as operating geothermal power plants. We accelerated our efforts to expand business development activities in those areas by, among other things, participating in new bids. In addition, we expect that a variety of governmental initiatives will create new opportunities for the development of new projects, as well as create additional markets for our products. These initiatives include the award of long-term contracts to independent power generators, the creation of competitive wholesale markets for selling and trading energy, capacity and related energy products and the adoption of programs designed to encourage "clean" renewable and sustainable energy sources.

In the Electricity segment, we expect intense competition from the solar and wind power generation industry to continue and increase. While we believe the expected demand for renewable energy will be large enough to accommodate increased competition, any such increase and the amount of renewable energy under contract as well as any further decline in natural gas prices due to increased production which can affect the market price for electricity may contribute to a reduction in electricity prices. Despite increased competition from the solar and wind power generation industry, we believe that base load electricity, such as geothermal-based energy, will continue to be an important source of renewable energy in areas with commercially viable geothermal resources. Also, geothermal power plants positively impact electrical grid stability and provide valuable ancillary services because of their base load nature. In the geothermal industry, due to reduced competition for geothermal leases we have experienced a decrease in the upfront fee required to secure geothermal leases.

In the Product segment, we experience increased competition from binary power plant equipment suppliers including the major steam turbine manufacturers. While we believe that we have a distinct competitive advantage based on our accumulated experience and current worldwide share of installed binary generation capacity, an increase in competition may impact our ability to secure new purchase orders from potential customers. The increased competition may also lead to a reduction in the prices that we are able to charge for our binary equipment, which in turn may reduce our profitability.

The 38 MW Puna complex has three PPAs, of which the 25 MW PPA has a monthly variable energy rate based on the local utility's avoided costs. A decrease in the price of oil will result in a decrease in the incremental cost that the power purchaser avoids by not generating its electrical energy needs from oil, which will result in a reduction of the energy rate that we may charge under this PPA. In order to reduce our exposure to oil we signed fixed rate PPAs for remaining 13 MW.

Since May 2012, the pricing under our PPAs for the Ormesa, Mammoth and Heber complexes for a total of 161 MW were variable rate based on SRAC pricing that is impacted by natural gas prices. However, in 2013, we signed new fixed rate PPAs that reduced our current exposure to SRAC by 18 MW and by additional 53 MW in December 2015. We entered into derivative transactions at a fixed price of $4.95 per MMbtu for the period from January 1, 2015 until March 31, 2015. In May 2015 we entered into a new derivative transaction at a fixed price of $3.00 per MMbtu and reduced our exposure to SRAC in the period from June 1, 2015 until December 31, 2015. In February 2016, we sold call options for total proceeds of $1.9 million at a fixed price of $2.00 per MMbtu to reduce our exposure to SRAC in the period from February 3, 2016 until December 29, 2016.

The viability of a geothermal resource depends on various factors such as the resource temperature, the permeability of the resource (i.e., the ability to get geothermal fluids to the surface) and operational factors relating to the extraction and injection of the geothermal fluids. Such factors, together with the possibility that we may fail to find commercially viable geothermal resources in the future, represent significant uncertainties that we face in connection with our growth expectations.

As our power plants (including their respective well fields) age, they may require increased maintenance with a resulting decrease in their availability, potentially leading to the imposition of penalties if we are not able to meet the requirements under our PPAs as a result of any decrease in availability.

Our foreign operations are subject to significant political, hostilities, economic and financial risks, which vary by country. As of the date of this annual report, those risks include security conditions in Israel, the partial privatization of the electricity sector in Guatemala and the political uncertainty currently prevailing in some of the countries in which we operate as further discussed above under “Risk Factors”. Although we maintain among other things political risk insurance for most of our investments in foreign power plants to mitigate these risks, insurance does not provide complete coverage with respect to all such risks.

The Sarulla 330 MW project was released for construction, and we began to recognize our first Product segment revenues under the supply contract we signed with the EPC contractor in the quarter ended September 30, 2014. Going forward we expect to derive significant revenues from the supply contract. We expect to generate additional income from our 12.75% equity investment in the Sarulla consortium following the commercial operation of the project. The Sarulla project’s future operations may be impacted by the current status of development as discussed above under “Description of Our Power Plants”, various factors which we do not control given our minority position in the consortium, as well as other factors discussed above under “Risk Factors”.

A Turkish sub-contractor provides us with certain locally manufactured equipment for renewable energy based generating facilities to help us meet our obligations under certain supply agreements in Turkey. The use of locally manufactured equipment in renewable energy based generating facilities in Turkey entitles such facilities to certain benefits under Turkish law, provided such facilities have obtained a RER Certificate from EMRA, which requires issuance of local manufacturing certificate. If we do not obtain the local manufacturing certificate then our customers, under the relevant supply agreements in Turkey, may not be issued an RER Certificate based on the equipment we supply to them, and we will be required to make a payment to such customers equal to the amount of the expected benefit.

FERC is allowed under PURPA to terminate, upon the request of a utility, the obligation of the utility to purchase the output of a Qualifying Facility if FERC finds that there is an accessible competitive market for energy and capacity from the Qualifying Facility. FERC has granted the California investor owned utilities a waiver of the mandatory purchase obligations from Qualifying Facilities above 20 MW. If the utilities in the regions in which our domestic power plants operate were to be relieved of the mandatory purchase obligation, they would not be required to purchase energy from us upon termination of the existing PPA, which could have an adverse effect on our revenues.

Revenues

We generate our revenues from the sale of electricity from our geothermal and recovered energy-based power plants; the design, manufacture and sale of equipment for electricity generation; and the construction, installation and engineering of power plant equipment.

Revenues attributable to our Electricity segment are derived from the sale of electricity from our power plants pursuant to long-term PPAs. While approximately 86% of our Electricity revenues for the year ended December 31, 2015 were derived from PPAs with fixed price components, we have variable price PPAs in California and Hawaii. Our 99 MW California SO#4 PPAs are subject to the impact of fluctuations in natural gas prices whereas the prices paid for electricity pursuant to the 25 MW PPA for the Puna complex in Hawaii are impacted by the price of oil. Accordingly, our revenues from those power plants may fluctuate.

Our Electricity segment revenues are also subject to seasonal variations, as more fully described in “Seasonality” below.

Our PPAs generally provide for energy payments alone, or energy and capacity payments. Generally, capacity payments are payments calculated based on the amount of time that our power plants are available to generate electricity. Some of our PPAs provide for bonus payments in the event that we are able to exceed certain target capacity levels and the potential forfeiture of payments if we fail to meet certain minimum target capacity levels. Energy payments, on the other hand, are payments calculated based on the amount of electrical energy delivered to the relevant power purchaser at a designated delivery point. The rates applicable to such payments are either fixed (subject, in certain cases, to certain adjustments) or are based on the relevant power purchaser’s avoided costs. Our more recent PPAs generally provide for energy payments alone with an obligation to compensate the off-taker for its incremental costs as a result of shortfalls in our supply.

Revenues attributable to our Product segment fluctuate between periods, mainly based on our ability to receive customer orders, the status and timing of such orders, delivery of raw materials and the completion of manufacturing. Larger customer orders for our products are typically the result of our participating in, and winning, tenders or requests for proposals issued by potential customers in connection with projects they are developing. Such projects often take a significant amount of time to design and develop and are subject to various contingencies, such as the customer’s ability to raise the necessary financing for a project. Consequently, we are generally unable to predict the timing of such orders for our products and may not be able to replace existing orders that we have completed with new ones. As a result, revenues from our Product segment fluctuate (sometimes, extensively) from period to period. In both 2014 and 2015, we experienced a significant increase in our Product segment customer orders, which has increased our Product segment backlog. The backlog for our Product segment as of February 23, 2016, is described above in Item 1 — “Business”.

The following table sets forth a breakdown of our revenues for the years indicated:

	Revenues (dollars in thousands)			% of Revenues for Period Indicated		
	Year Ended December 31,			Year Ended December 31,		
	2015	**2014**	**2013**	**2015**	**2014**	**2013**
Revenues:						
Electricity	$375,920	$382,301	$329,747	63.2 %	68.3 %	61.8 %
Product	218,724	177,223	203,492	36.8	31.7	38.2
Total revenues	$594,644	$559,524	$533,239	100.0%	100.0%	100.0%

Geographic Breakdown of Revenues

The following table sets forth the geographic breakdown of the revenues attributable to our Electricity and Product segments for the years indicated:

	Revenues in Thousands			% of Revenues for Period Indicated		
	Year Ended December 31,			Year Ended December 31,		
	2015	**2014**	**2013**	**2015**	**2014**	**2013**
Electricity Segment:						
United States	$261,478	$268,198	$246,112	69.6 %	70.2 %	74.6 %
Foreign	114,442	114,103	83,635	30.4	29.8	25.4
Total	$375,920	$382,301	$329,747	100.0%	100.0%	100.0%
Product Segment:						
United States	$19,838	$17,000	$55,101	9.1 %	9.6 %	27.1 %
Foreign	198,886	160,223	148,391	90.9	90.4	72.9
Total	$218,724	$177,223	$203,492	100.0%	100.0%	100.0%

Seasonality

The prices paid for the electricity generated by some of our domestic power plants pursuant to our PPAs are subject to seasonal variations. The prices (mainly for capacity) paid for electricity under the PPAs with Southern California Edison and PG&E in California for the Heber 2 power plant in the Heber complex, the Mammoth complex, the Ormesa complex, and the North Brawley power plant are higher in the months of June through September. As a result, we receive, and expect to continue to receive in the future, higher revenues from these projects during such months. In the winter, our power plants produce more energy principally due to the lower ambient temperature, which has a favorable impact on the energy component of our Electricity revenues. The higher payments payable by Southern California Edison and PG&E in the summer months offset the negative impact on our revenues from generally lower generation in the summer due to the higher ambient temperature

Breakdown of Cost of Revenues

Electricity Segment

The principal cost of revenues attributable to our operating power plants includes operation and maintenance expenses comprised of salaries and related employee benefits, equipment expenses, costs of parts and chemicals, costs related to third-party services, lease expenses, royalties, startup and auxiliary electricity purchases, property taxes, insurance and, for some of our projects, purchases of make-up water for use in our cooling towers and also depreciation and amortization. In our California power plants our principal cost of revenues also includes transmission charges and scheduling charges. In some of our Nevada power plants we also incur wheeling charges. Some of these expenses, such as parts, third-party services and major maintenance, are not incurred on a regular basis. This results in fluctuations in our expenses and our results of operations for individual power plants from quarter to quarter. Payments made to government agencies and private entities on account of site leases where plants are located are included in cost of revenues. Royalty payments, included in cost of revenues, are made as compensation for the right to use certain geothermal resources and are calculated as a percentage of the revenues derived from the associated geothermal rights. Royalties constituted approximately 4.1% and 4.3% of Electricity segment revenues for the years ended December 31, 2015 and December 31, 2014, respectively.

Product Segment

The principal cost of revenues attributable to our Product segment includes materials, salaries and related employee benefits, expenses related to subcontracting activities, and transportation expenses. Sales commissions to sales representatives are included in selling and marketing expenses. Some of the principal expenses attributable to our Product segment, such as a portion of the costs related to labor, utilities and other support services are fixed, while others, such as materials, construction, transportation and sales commissions, are variable and may fluctuate significantly, depending on market conditions. As a result, the cost of revenues attributable to our Product segment, expressed as a percentage of total revenues, fluctuates. Another reason for such fluctuation is that in responding to bids for our products, we price our products and services in relation to existing competition and other prevailing market conditions, which may vary substantially from order to order.

Cash and Cash Equivalents

Our cash and cash equivalents, as of December 31, 2015 increased to $185.9 million from $40.2 million as of December 31, 2014. This increase is principally due to: (i) $190.0 million derived from operating activities during the year ended December 31, 2015; (ii) $156.6 million net proceeds derived from the issuance of shares to noncontrolling interest; (iii) $42.0 million of proceeds from the loan for our Amatitlan power plant; (iv) $15.4 million derived from our share exchange transaction with Ormat Industries; and (v) a net change in restricted cash and cash equivalents of $43.7 million. This increase was partially offset by: (i) our use of $152.1 million to fund capital expenditures; (ii) $30.6 million of cash paid to repurchase a portion of our OFC Senior Secured Notes; (iii) net repayment of $71.7 million of long-term debt; (iv) repayment of $20.3 million of our revolving credit lines with commercial banks; (v) $19.1 million cash paid to a noncontrolling interest; and (vi) payment of a $12.7 million cash dividend. Our corporate borrowing capacity under committed lines of credit with different commercial banks as of December 31, 2015 was $532.5 million, as described below in “Liquidity and Capital Resources”, of which we have utilized $387.2 million as of December 31, 2015.

Critical Accounting Estimates and Assumptions

Our significant accounting policies are more fully described in Note 1 to our consolidated financial statements set forth in Item 8 of this annual report. However, certain of our accounting policies are particularly important to an understanding of our financial position and results of operations. In applying these critical accounting estimates and assumptions, our management uses its judgment to determine the appropriate assumptions to be used in making certain estimates. Such estimates are based on management’s historical experience, the terms of existing contracts, management’s observance of trends in the geothermal industry, information provided by our customers and information available to management from other outside sources, as appropriate. Such estimates are subject to an inherent degree of uncertainty and, as a result, actual results could differ from our estimates. Our critical accounting policies include:

- *Revenues and Cost of Revenues.* Revenues related to the sale of electricity from our geothermal and REG power plants and capacity payments paid in connection with such sales (electricity revenues) are recorded based upon output delivered and capacity provided by such power plants at rates specified pursuant to the relevant PPAs. Revenues related to PPAs accounted for as operating leases with minimum lease rentals which vary over time are generally recognized on a straight-line basis over the term of the PPA.

Revenues generated from the construction of geothermal and recovered energy-based power plant equipment and other equipment on behalf of third parties (product revenues) are recognized using the percentage of completion method, which requires estimates of future costs over the full term of product delivery. Such cost estimates are made by management based on prior operations and specific project characteristics and designs. If management's estimates of total estimated costs with respect to our Product segment are inaccurate, then the percentage of completion is inaccurate resulting in an over- or under-estimate of gross margins. As a result, we review and update our cost estimates on significant contracts on a quarterly basis, and at least on an annual basis for all others, or when circumstances change and warrant a modification to a previous estimate. Changes in job performance, job conditions, and estimated profitability, including those arising from the application of penalty provisions in relevant contracts and final contract settlements, may result in revisions to costs and revenues and are recognized in the period in which the revisions are determined. Provisions for estimated losses relating to contracts are made in the period in which such losses are determined. Revenues generated from engineering and operating services and sales of products and parts are recorded once the service is provided or product delivery is made, as applicable.

- *Property, Plant and Equipment.* We capitalize all costs associated with the acquisition, development and construction of power plant facilities. Major improvements are capitalized and repairs and maintenance (including major maintenance) costs are expensed. We estimate the useful life of our power plants to range between 25 and 30 years. Such estimates are made by management based on factors such as prior operations, the terms of the underlying PPAs, geothermal resources, the location of the assets and specific power plant characteristics and designs. Changes in such estimates could result in useful lives which are either longer or shorter than the depreciable lives of such assets. We periodically re-evaluate the estimated useful life of our power plants and revise the remaining depreciable life on a prospective basis.

We capitalize costs incurred in connection with the exploration and development of geothermal resources beginning when we acquire land rights to the potential geothermal resource. Prior to acquiring land rights, we make an initial assessment that an economically feasible geothermal reservoir is probable on that land using available data and external assessments vetted through our exploration department and occasionally outside service providers. Costs incurred prior to acquiring land rights are expensed. It normally takes two to three years from the time we start active exploration of a particular geothermal resource to the time we have an operating production well, assuming we conclude the resource is commercially viable.

In most cases, we obtain the right to conduct our geothermal development and operations on land owned by the BLM, various states or with private parties. In consideration for certain of these leases, we may pay an up-front non-refundable bonus payment which is a component of the competitive lease process. This payment and other related costs are capitalized and included in construction-in-process. Once we acquire land rights to the potential geothermal resource, we perform additional activities to assess the commercial viability of the resource. Such activities include, among others, conducting surveys and other analyses, obtaining drilling permits, creating access roads to drilling sites, and exploratory drilling which may include temperature gradient holes and/or slim holes. Such costs are capitalized and included in construction-in-process. Once our exploration activities are complete, we finalize our assessment as to the commercial viability of the geothermal resource and either proceed to the construction phase for a power plant or abandon the site. If we decide to abandon a site, all previously capitalized costs associated with the exploration project are written off.

Our assessment of economic viability of an exploration project involves significant management judgment and uncertainties as to whether a commercially viable resource exists at the time we acquire land rights and begin to capitalize such costs. As a result, it is possible that our initial assessment of a geothermal resource may be incorrect and we will have to write-off costs associated with the project that were previously capitalized. For example, during the years ended December 31, 2015, and 2014, we determined that the geothermal resource at two and three of our exploration projects, respectively, would not support commercial operations and as such, we abandoned those sites. As a result of this determination, we expensed $1,579,000 and $15,439,000 of capitalized costs during the years ended December 31, 2015 and 2014, respectively. Due to the uncertainties inherent in geothermal exploration, these historical impairments may not be indicative of future impairments. Included in construction-in-process are costs related to projects in exploration and development of $82,862,000 and $73,431,000 at December 31, 2015 and 2014, respectively. Included in this amount, $26,491,000 and $26,618,000 relates to up-front bonus payments at December 31, 2015 and 2014, respectively.

- *Impairment of Long-Lived Assets and Long-Lived Assets to be Disposed of.* We evaluate long-lived assets, such as property, plant and equipment and construction-in-process for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. Factors which could trigger an impairment include, among others, significant underperformance relative to historical or projected future operating results, significant changes in our use of assets or our overall business strategy, negative industry or economic trends, a determination that an exploration project will not support commercial operations, a determination that a suspended project is not likely to be completed, a significant increase in costs necessary to complete a project, legal factors relating to our business or when we conclude that it is more likely than not that an asset will be disposed of or sold.

We test our operating plants that are operated together as a complex for impairment at the complex level because the cash flows of such plants result from significant shared operating activities. For example, the operating power plants in a complex are managed under a combined operation management generally with one central control room that controls and one maintenance group that services all of the power plants in a complex. As a result, the cash flows from individual plants within a complex are not largely independent of the cash flows of other plants within the complex. We test for impairment of our operating plants which are not operated as a complex, as well as our projects under exploration, development or construction that are not part of an existing complex, at the plant or project level. To the extent an operating plant becomes part of a complex in the future, we will test for impairment at the complex level.

Recoverability of assets to be held and used is measured by a comparison of the carrying amount of an asset to the estimated future net undiscounted cash flows expected to be generated by the asset. The significant assumptions that we use in estimating our undiscounted future cash flows include (i) projected generating capacity of the power plant and rates to be received under the respective PPA and (ii) projected operating expenses of the relevant power plant. Estimates of future cash flows used to test recoverability of a long-lived asset under development also include cash flows associated with all future expenditures necessary to develop the asset. If future cash flows are less than the assumptions we used in such estimates, we may incur impairment losses in the future that could be material to our financial condition and/or results of operations.

If our assets are considered to be impaired, the impairment to be recognized is the amount by which the carrying amount of the assets exceeds their fair value. Assets to be disposed of are reported at the lower of the carrying amount or fair value less costs to sell. We believe that for year ended December 31, 2015, no impairment exists for any of our long-lived assets; however, estimates as to the recoverability of such assets may change based on revised circumstances. Estimates of the fair value of assets require estimating useful lives and selecting a discount rate that reflects the risk inherent in future cash flows.

- *Obligations Associated with the Retirement of Long-Lived Assets.* We record the fair market value of legal liabilities related to the retirement of our assets in the period in which such liabilities are incurred. These liabilities include our obligation to plug wells upon termination of our operating activities, the dismantling of our power plants upon cessation of our operations, and the performance of certain remedial measures related to the land on which such operations were conducted. When a new liability for an asset retirement obligation is recorded, we capitalize the costs of such liability by increasing the carrying amount of the related long-lived asset. Such liability is accreted to its present value each period and the capitalized cost is depreciated over the useful life of the related asset. At retirement, we either settle the obligation for its recorded amount or report either a gain or a loss with respect thereto. Estimates of the costs associated with asset retirement obligations are based on factors such as prior operations, the location of the assets and specific power plant characteristics. We review and update our cost estimates periodically and adjust our asset retirement obligations in the period in which the revisions are determined. If actual results are not consistent with our assumptions used in estimating our asset retirement obligations, we may incur additional losses that could be material to our financial condition or results of operations.

- *Accounting for Income Taxes.* Significant estimates are required to arrive at our consolidated income tax provision and other tax balances. This process requires us to estimate our actual current tax exposure and to make an assessment of temporary differences resulting from differing treatments of items for tax and accounting purposes. Such differences result in deferred tax assets and liabilities which are included in our consolidated balance sheets. For those jurisdictions where the projected operating results indicate that realization of our net deferred tax assets is not more likely than not, a valuation allowance is recorded.

We evaluate our ability to utilize the deferred tax assets quarterly and assess the need for the valuation allowance. In assessing the need for a valuation allowance, we estimate future taxable income, considering the feasibility of ongoing tax planning strategies and the realization of tax loss carryforwards. Valuation allowances related to deferred tax assets can be affected by changes in tax laws, statutory tax rates, and future taxable income. We have recorded a valuation allowance related to our U.S. deferred tax assets. In the future, if there is sufficient evidence that we will be able to generate sufficient future taxable income in the U.S., we may be required to reduce this valuation allowance, resulting in income tax benefits in our consolidated statement of operations.

In the ordinary course of business, there is inherent uncertainty in quantifying our income tax positions. We assess our income tax positions and record tax benefits for all years subject to examination based upon management's evaluation of the facts, circumstances and information available at the reporting date. For those tax positions where it is more likely than not that a tax benefit will be sustained, which is greater than 50% likelihood of being realized upon ultimate settlement with a taxing authority that has full knowledge of all relevant information, we recognize between 0 to 100% of the tax benefit. For those income tax positions where it is not more likely than not that a tax benefit will be sustained, we do not recognize any tax benefit in the consolidated financial statements. Resolution of these uncertainties in a manner inconsistent with our expectations could have a material impact on our financial condition or results of operations.

New Accounting Pronouncements

See Note 1 to our consolidated financial statements set forth in Item 8 of this annual report for information regarding new accounting pronouncements.

Results of Operations

Our historical operating results in dollars and as a percentage of total revenues are presented below. A comparison of the different years described below may be of limited utility due to (i) our recent construction or disposition of new power plants and enhancement of acquired power plants and (ii) fluctuation in revenues from our Product segment.

	Year Ended December 31,		
	2015	**2014**	**2013**
	(Dollars in thousands, except per share data)		
Statements of Operations and Historical Data:			
Revenues:			
Electricity	$375,920	$382,301	$329,747
Product	218,724	177,223	203,492
	594,644	559,524	533,239
Cost of revenues:			
Electricity	242,612	246,630	232,874
Product	133,753	109,143	140,547
	376,365	355,773	373,421
Gross margin			
Electricity	133,308	135,671	96,873
Product	84,971	68,080	62,945
	218,279	203,751	159,818
Operating expenses:			
Research and development expenses	1,780	783	4,965
Selling and marketing expenses	16,077	15,425	24,613
General and administrative expenses	34,782	28,614	29,188
Write-off of unsuccessful exploration activities	1,579	15,439	4,094
Operating income	164,061	143,490	96,958
Other income (expense):			
Interest income	297	312	1,332
Interest expense, net	(72,577)	(84,654)	(73,776)
Foreign currency translation and transaction gains (losses)	(1,622)	(5,839)	5,085
Income attributable to sale of tax benefits	25,431	24,143	19,945
Gain from sale of property, plant and equipment	—	7,628	—
Other non-operating income (expense), net	(1,991)	756	1,592
Income from continuing operations before income taxes equity in income of investees and equity in losses of investees	113,599	85,836	51,136
Income tax (provision) benefit	15,258	(27,608)	(13,552)
Equity in losses of investees, net	(5,508)	(3,213)	(250)
Income from continuing operations	123,349	55,015	37,334
Discontinued operations:			
Income from discontinued operations (including gain on disposal of $0, $0 and $3,646, respectively)	—	—	5,311

Income tax provision	—	—	(614)
Total income from discontinued operations	—	—	4,697
Net income	123,349	55,015	42,031
Net income attributable to noncontrolling interest	(3,776)	(833)	(793)
Net income attributable to the Company's stockholders	$119,573	$54,182	$41,238
Earnings per share attributable to the Company's stockholders:			
Basic:			
Income from continuing operations	$2.46	$1.19	$0.81
Discontinued operations	—	—	0.10
Net income	$2.46	$1.19	$0.91
Diluted:			
Income from continuing operations	$2.43	$1.18	$0.81
Discontinued operations	—	—	0.10
Net income	$2.43	$1.18	$0.91
Weighted average number of shares used in computation of earnings per share attributable to the Company's stockholders:			
Basic	48,562	45,508	45,440
Diluted	49,187	45,859	45,475

	Year Ended December 31,		
	2015	2014	2013
Statements of Operations Data:			
Revenues:			
Electricity	63.2 %	68.3 %	61.8 %
Product	36.8	31.7	38.2
	100.0	100.0	100.0
Cost of revenues:			
Electricity	64.5	64.5	70.6
Product	61.2	61.6	69.1
	63.3	63.6	70.0
Gross margin			
Electricity	35.5	35.5	29.4
Product	38.8	38.4	30.9
	36.7	36.4	30.0
Operating expenses:			
Research and development expenses	0.3	0.1	0.9
Selling and marketing expenses	2.7	2.8	4.6
General and administrative expenses	5.8	5.1	5.5
Impairment charge	0.0	0.0	0.0
Write-off of unsuccessful exploration activities	0.3	2.8	0.8
Operating income	27.6	25.6	18.2
Other income (expense):			
Interest income	0.0	0.1	0.2
Interest expense, net	(12.2)	(15.1)	(13.8)
Foreign currency translation and transaction gains (losses)	(0.3)	(1.0)	1.0
Income attributable to sale of tax benefits	4.3	4.3	3.7
Gain from sale of property, plant and equipment	0.0	1.4	0.0
Other non-operating income (expense), net	(0.3)	0.1	0.3
Income from continuing operations before income taxes and equity in losses of investees	19.1	15.3	9.6
Income tax (provision) benefit	2.6	(4.9)	(2.5)
Equity in losses of investees, net	(0.9)	(0.6)	(0.0)
Income from continuing operations	20.7	9.8	7.0
Discontinued operations:			
Income from discontinued operations (including gain on disposal of $0, $0 and $3,646, respectively)	0.0	0.0	1.0
Income tax provision	0.0	0.0	(0.1)
Total income from discontinued operations	0.0	0.0	0.9
Net income		9.8	7.9
Net income attributable to noncontrolling interest	(0.6)	(0.1)	(0.1)
Net income attributable to the Company's stockholders	20.1 %	9.7 %	7.7 %

Comparison of the Year Ended December 31, 2015 and the Year Ended December 31, 2014

Total Revenues

Total revenues for the year ended December 31, 2015 were $594.6 million, compared to $559.5 million for the year ended December 31, 2014, representing a 6.3% increase from the prior period. This increase was attributable to our Product segment, in which revenues increased by 23.4% compared to the corresponding period in 2014. This increase was partially offset by a 1.7% decrease in our Electricity segment revenues over the corresponding period in 2014.

Electricity Segment

Revenues attributable to our Electricity segment for the year ended December 31, 2015 were $375.9 million, compared to $382.3 million for the year ended December 31, 2014, representing a 1.7% decrease from the prior period. This decrease was primarily attributable to a $30.0 million reduction in revenues generated by some of our power plants due to lower oil and gas prices and due to our Puna power plant having lower generation due to a hurricane. This decrease was partially offset by the commencement of operations of the second phase of the McGinness Hills power plant and Don A. Campbell power plant in Nevada in February 2015 and September 2015, respectively.

Power generation in our power plants increased by 8.6% from 4,450,910 MWh in the year ended December 31, 2014 to 4,835,109 MWh in the year ended December 31, 2015, mainly due to commencement of commercial operation of the second phase of the McGinness Hills power plant and Don A. Campbell power plant, partially offset by the decrease in generation of the Puna and North Brawley power plants.

Product Segment

Revenues attributable to our Product segment for the year ended December 31, 2015 were $218.7 million, compared to $177.2 million for the year ended December 31, 2014, which represented a 23.4% increase. This increase in our Product segment revenues was primarily due to timing of revenue recognition, different product mix and commencing revenue recognition for new contracts.

Total Cost of Revenues

Total cost of revenues for the year ended December 31, 2015 was $376.4 million, compared to $355.8 million for the year ended December 31, 2014, representing a 5.8% increase from the prior period. This increase was primarily due to the increase in cost of revenues from our Product segment, partially offset by a decrease in cost of revenues from our Electricity segment. As a percentage of total revenues, our total cost of revenues for the year ended December 31, 2015 decreased to 63.3%, compared to 63.6% for the year ended December 31, 2014. This decrease was attributable to a decrease in cost of revenues as a percentage of total revenues, in both our Electricity and Product segments.

Electricity Segment

Total cost of revenues attributable to our Electricity segment for the year ended December 31, 2015 was $242.6 million, compared to $246.6 million for the year ended December 31, 2014, representing a 1.6% decrease from the prior period. This decrease was primarily due to: (i) reimbursement of $2.5 million of mining tax imposed on us based on an audit performed by the state of Nevada for the years ended December 31, 2008, 2009 and 2010 following our successful appeal of the audit decision in the first quarter of 2015 and (ii) the fact that in the year ended December 31, 2015 we did not incur costs that we incurred in the year ended December 31, 2014 to address the North Brawley power plant uncontrolled well flow. This decrease in our electricity cost of revenues was partially offset by additional cost of revenues from the second phase of the McGinness Hills power plant and Don A. Campbell power plant that commenced commercial operation in February 2015 and September 2015, respectively, as discussed above. As a percentage of total Electricity segment revenues, the total cost of revenues attributable to our Electricity segment for the year ended December 31, 2015 was 64.5%, compared to 64.5% for the year ended December 31, 2014.

Product Segment

Total cost of revenues attributable to our Product segment for the year ended December 31, 2015 was $133.8 million, compared to $109.1 million for the year ended December 31, 2014, representing a 22.5% increase from the prior period. This increase was primarily attributable to the increase in Product segment revenues as discussed above. As a percentage of total Product segment revenues, our total cost of revenues attributable to the Product segment for the year ended December 31, 2015 was 61.2%, compared to 61.6% for the year ended December 31, 2014. This decrease was mainly attributable to the different product mix and different margins in the various sales contracts we entered into for this segment during these periods, as well as improvements made at our manufacturing plant.

Research and Development Expenses

Research and development expenses for the year ended December 31, 2015 were $1.8 million, compared to $0.8 million for the year ended December 31, 2014. Research and development expenses are net of grants from the DOE in the amount of $0 and $0.5 million for the years ended December 31, 2015 and 2014, respectively, related to the EGS.

Selling and Marketing Expenses

Selling and marketing expenses for the year ended December 31, 2015 were $16.1 million, compared to $15.4 million for the year ended December 31, 2014. This increase was primarily due to higher sales commissions related to our Product segment due to higher revenues and different commissions mix. Selling and marketing expenses for the year ended December 31, 2015 constituted 2.7% of total revenues for such year, compared to 2.8% of such revenues for the year ended December 31, 2014.

General and Administrative Expenses

General and administrative expenses for the year ended December 31, 2015 were $34.8 million, compared to $28.6 million for the year ended December 31, 2014.

This increase was mainly due to $3.8 million of expenses related to the share exchange with Ormat Industries, as discussed above under “Recent Developments”. General and administrative expenses for the year ended December 31, 2015, excluding the costs related to the share exchange, constituted 5.2% and 5.1% of total revenues for the years ended December 31, 2015 and 2014, respectively.

Write-off of Unsuccessful Exploration Activities

Write-off of unsuccessful exploration activities for the year ended December 31, 2015 was $1.6 million compared to $15.4 million for the year ended December 31, 2014. The majority of the write-off of unsuccessful exploration activities for the year ended December 31, 2015 represented the costs related to the Maui prospect in Hawaii, which we determined in the fourth quarter of 2015 would not support commercial operations. Write-off of unsuccessful exploration activities for the year ended December 31, 2014 represented the costs of $8.1 million related to our exploration activities in the Wister site in California, and $7.3 million related to our exploration activities in the Mount Spurr site in Alaska, which we determined in the second and the fourth quarters of 2014, respectively, would not support commercial operations.

Operating Income

Operating income for the year ended December 31, 2015 was $164.1 million, compared to $143.5 million for the year ended December 31, 2014, representing a 14.4% increase from the prior period. This increase was primarily attributable to the write-off of unsuccessful exploration activities in the amount of $15.4 million for the year ended December 31, 2014 and to an increase in our gross margin in our Product segment, as discussed above. The increase was partially offset by costs associated with the share exchange, as discussed above. Operating income attributable to our Electricity segment for the year ended December 31, 2015 was $99.3 million, compared to $90.4 million for the year ended December 31, 2014. This increase was primarily attributable to a decrease in write-off of unsuccessful exploration activities in the amount of $13.9 million ended December 31, 2014 as described above. Operating income attributable to our Product segment for the year ended December 31, 2015 was $64.7 million, compared to $53.1 million for the year ended December 31, 2014.

Interest Expense, Net

Interest expense, net, for the year ended December 31, 2015 was $72.6 million, compared to $84.7 million for the year ended December 31, 2014, representing a 14.3% decrease from the prior period. This decrease was primarily due to: (i) lower interest expense as a result of principal payments of long term debt and revolving credit lines with banks; (ii) a $2.8 million decrease in interest related to the sale of tax benefits; and (iii) $0.9 million increase related to interest capitalized to projects. The decrease was partially offset by an increase in interest expense related to a loan in the amount of $140.0 million received under the OFC 2 Senior Secured Notes to finance the construction of second phase of McGinness Hills power plant in August 2014.

Foreign Currency Translation and Transaction Losses

Foreign currency translations and transaction losses for the year ended December 31, 2015 were $1.6 million, compared to $5.8 million for the year ended December 31, 2014. Foreign currency translations and transaction losses were attributable primarily to losses on foreign currency forward contracts which were not accounted for as hedge transactions.

Income Attributable to Sale of Tax Benefits

Income attributable to the sale of tax benefits to institutional equity investors (as described below under “OPC Transaction” and “ORTP Transaction”) for the year ended December 31, 2015 was $25.4 million, compared to $24.1 million for the year ended December 31, 2014. This income represents the value of PTCs and taxable income or loss generated by OPC and ORTP and allocated to investors in the amount of $5.3 million and $20.1 million, respectively, in the year ended December 31, 2015, compared to $7.0 million and $17.1 million, respectively, in the year ended December 31, 2014. This increase was primarily attributable to a higher taxable loss in ORTP, partially offset by lower depreciation for tax purposes in OPC as a result of declining depreciation rates under MACRS.

Gain from Sale of Property, Plant and Equipment

There was no gain from the sale of property, plant and equipment for the year ended December 31, 2015. Gain from the sale of property, plant and equipment for the year ended December 31, 2014 was $7.6 million. This gain relates to the sale of the Heber Solar project in Imperial County, California for an aggregate purchase price of $35.25 million in the first quarter of 2014. We received the first payment of $15.0 million in the first quarter of 2014, and the second payment of the remaining $20.25 million in the second quarter of 2014. We recognized the gain in the second quarter of 2014.

Other non-operating income (loss)

Other non-operating loss for the year ended December 31, 2015 was $2.0 million, compared to non-operating income of $0.8 million in the year ended December 31, 2014. Other non-operating loss for the year ended December 31, 2015 includes a capital loss of $1.7 million resulting from the repurchase of $30.6 million aggregate principal amount of the OFC Senior Secured Notes.

Income Taxes

Income tax benefit for the year ended December 31, 2015 was $15.3 million, compared to income tax provision of $27.6 million for the year ended December 31, 2014. Income tax benefit for the year ended December 31, 2015 includes a $49.4 million deferred tax asset relating to the release of the valuation allowance for the additional 50% investment deduction for our Olkaria 3 power plant based on amendments to the Kenya Income Tax Act that came into effect on September 11, 2015 and which extended the period to utilize such investment deduction from five years to ten years. Income tax provision for the year ended December 31, 2015, excluding the $49.4 million deferred tax asset, was $34.1 million, compared to $27.6 million for the year ended December 31, 2014. This increase in income tax provision primarily resulted from the increase in income before taxes in jurisdictions outside the U.S. Our effective tax rate for the years ended December 31, 2015, excluding the $49.4 million deferred tax asset, and 2014, was 28.8% and 32.2%, respectively. The effective tax rate differs from the federal statutory rate of 35% for the year ended December 31, 2015 primarily due to losses in the U.S. and certain foreign jurisdictions.

For the year ended December 31, 2015 and 2014, we recorded a valuation allowance in the amount of approximately $70.5 million and $111.3 million respectively, against our U.S. deferred tax assets in respect of net operating loss (NOL) carryforwards and unutilized tax credits (PTCs and ITCs). As of December 31, 2015 we had U.S. federal NOLs in the amount of approximately $261.0 million, state NOLs in the amount of approximately $191.0 million, and unutilized tax credits of approximately $72.0 million, all of which can be carried forward for 20 years. The related deferred tax assets totaled approximately $70.5 million. Realization of these deferred tax assets and tax credits is dependent on generating sufficient taxable income in the U.S. prior to expiration of the NOL carryforwards and tax credits. The scheduled reversal of deferred tax liabilities, projected future taxable income and tax planning strategies were considered in determining the amount of valuation allowance. A valuation allowance in the amount of $70.5 million was recorded against the U.S. deferred tax assets as of December 31, 2015 as at that point in time, we believe it is more likely than not that the deferred tax assets will not be realized. In 2016 or in future years , if sufficient additional evidence of our ability to generate taxable income is established in the future we may be required to reduce or fully release the valuation allowance, resulting in income tax benefits in our consolidated statement of operations.

Equity in losses of investees, net

Equity in losses of investees, net in the year ended December 31, 2015 was $5.5 million, compared to $3.2 million in the year ended December 31, 2014. Equity in losses of investees, net derived from our 12.75% share in the losses of the Sarulla project and from profits elimination.

Net Income

Net income for the year ended December 31, 2015 was $123.3 million, compared to $55.0 million for the year ended December 31, 2014, representing an increase of $68.3 million, or 124.2% from the prior period. This increase in net income was principally attributable to the deferred tax asset in Kenya and related expenses in the amount of $48.7 million, the increase of $20.6 million in operating income and the decrease in interest expense of $12.1 million, as discussed above. The increase was partially offset by a $7.6 million gain from the sale of property, plant and equipment for the year ended December 31, 2014, as discussed above.

Comparison of the Year Ended December 31, 2014 and the Year Ended December 31, 2013

Total Revenues

Total revenues for the year ended December 31, 2014 were $559.5 million, compared to $533.2 million for the year ended December 31, 2013, representing a 4.9% increase from the prior period. This increase was attributable to our Electricity segment, in which revenues increased by 15.9% over the corresponding period in 2013. This increase was partially offset by a 12.9% decrease in our Product segment revenues over the corresponding period in 2013.

Electricity Segment

Revenues attributable to our Electricity segment for the year ended December 31, 2014 were $382.3 million, compared to $329.7 million for the year ended December 31, 2013, representing a 15.9% increase from the prior period. This increase was primarily due to: (i) the increase in generation as a result of the commencement of operations of our Plant 2 and 3 at the Olkaria III complex in Kenya, which commenced commercial operations in May 2013 and January 2014, respectively, and our Don A. Campbell phase 1power plant in Nevada, which commenced commercial operations in December 2013; (ii) higher energy rates under the SO#4 contracts; and (iii) net gain on derivative contracts on oil and natural gas prices of $5.7 million in the year ended December 31, 2014, compared to a net loss of $5.0 million over the corresponding period in 2013.

Power generation in our power plants increased by 4.6% from 4,253,910 MWh in the year ended December 31, 2013 to 4,450,910 MWh in the year ended December 31, 2014.

Product Segment

Revenues attributable to our Product segment for the year ended December 31, 2014 were $177.2 million, compared to $203.5 million for the year ended December 31, 2013, representing a 12.9% decrease from the prior period. This decrease was primarily due to timing of revenue recognition and different product mix.

Total Cost of Revenues

Total cost of revenues for the year ended December 31, 2014 was $355.8 million, compared to $373.4 million for the year ended December 31, 2013, representing a 4.7% decrease from the prior period. This decrease was primarily due to the decrease in cost of revenues from our Product segment. The decrease was partially offset by an increase in cost of revenues from our Electricity segment. As a percentage of total revenues, our total cost of revenues for the year ended December 31, 2014 decreased to 63.6%, compared to 70.0% for the year ended December 31, 2013. This decrease was attributable to a decrease in cost of revenues as a percentage of total revenues, in both our Electricity and Product segments, as further explained below.

Electricity Segment

Total cost of revenues attributable to our Electricity segment for the year ended December 31, 2014 was $246.6 million, compared to $232.9 million for the year ended December 31, 2013, representing a 5.9% increase from the prior period. This increase was primarily due to additional cost of revenues from the new power plants that commenced commercial operation in 2013 and 2014, as discussed above. As a percentage of total Electricity segment revenues, the total cost of revenues attributable to our Electricity segment for the year ended December 31, 2014 was 64.5%, compared to 70.6% for the year ended December 31, 2013. This decrease was mainly due to new power plants that came on line with lower operating expenses due to higher efficiency.

Product Segment

Total cost of revenues attributable to our Product segment for the year ended December 31, 2014 was $109.1 million, compared to $140.5 million for the year ended December 31, 2013, representing a 22.3% decrease from the prior period. This decrease was primarily attributable to the decrease in Product segment revenues as discussed above. As a percentage of total Product segment revenues, our total cost of revenues attributable to the Product segment for the year ended December 31, 2014 was 61.6%, compared to 69.1% for the year ended December 31, 2013. This decrease was primarily attributable to the different product mix and different margins in the various sales contracts we entered into for this segment during these periods, as well as manufacturing enhancements made during 2014.

Research and Development Expenses

Research and development expenses excluding grants from the DOE were $1.3 million for the year ended December 31, 2014, compared to $6.6 million for the year ended December 31, 2013. Research and development expenses are net of grants from the DOE in the amount of $0.5 million and $1.6 million for the years ended December 31, 2014 and 2013, respectively, related to the EGS project. Research and development expenses for the year ended December 31, 2014 were $0.8 million, compared to $5.0 million for the year ended December 31, 2013.

Selling and Marketing Expenses

Selling and marketing expenses for the year ended December 31, 2014 were $15.4 million, compared to $24.6 million for the year ended December 31, 2013. This decrease was primarily due to a one-time early termination fee in the amount of $9.0 million we paid to SCE in the first quarter of 2013 to terminate PPAs for the G1 and G3 power plants in the Mammoth complex, and from a $2.6 million termination fee paid to NV Energy related to the termination of the Dixie Meadows PPA. The decrease was partially offset by higher sales commissions related to our Product segment due to different commissions mix. Excluding the one-time termination fees, selling and marketing expenses for the year ended December 31, 2014 constituted 2.8% of total revenues for such year, compared to 2.4% of such revenues for the year ended December 31, 2013.

General and Administrative Expenses

General and administrative expenses for the year ended December 31, 2014 were $28.6 million, compared to $29.2 million for the year ended December 31, 2013. General and administrative expenses for the year ended December 31, 2014, constituted 5.1% of total revenues for such year, compared to 5.5% for the year ended December 31, 2013.

Write-off of Unsuccessful Exploration Activities

Write-off of unsuccessful exploration activities for the year ended December 31, 2014 was $15.4 million compared to $4.1 million for the year ended December 31, 2013. Write-off of unsuccessful exploration activities for the year ended December 31, 2014 represented the costs of $8.1 million related to our exploration activities in the Wister site in California, and $7.3 million related to our exploration activities in the Mount Spurr site in Alaska, which we determined in the second and the fourth quarters of 2014, respectively, would not support commercial operations. The majority of the write-off of unsuccessful exploration activities for the year ended December 31, 2013 represented the costs (including land costs) related to the Drum Mountain prospect in Utah, which we determined in the fourth quarter of 2013 would not support commercial operations.

Operating Income

Operating income for the year ended December 31, 2014 was $143.5 million, compared to $97.0 million for the year ended December 31, 2013, representing an increase of 48.0% from the prior period. This increase was primarily attributable to: (i) the increase in our gross margin in our Electricity segment and (ii) one-time early termination fees of $11.6 million included in 2013 in selling and marketing expenses discussed above. The increase was partially offset by the write-off of unsuccessful exploration activities, as discussed above. Operating income attributable to our Electricity segment for the year ended December 31, 2014 was $90.4 million, compared to $54.3 million for the year ended December 31, 2013. Operating income attributable to our Product segment for the year ended December 31, 2014 was $53.1 million, compared to $42.7 million for the year ended December 31, 2013.

Interest Expense, Net

Interest expense, net, for the year ended December 31, 2014 was $84.7 million, compared to $73.8 million for the year ended December 31, 2013, which represented a 14.7% increase. This increase was primarily due to: (i) the conversion in July 2013 of the interest rate under our OPIC loans from a floating interest rate to fixed interest rate; and (ii) a $4.4 million decrease related to interest capitalized to projects.

Foreign Currency Translation and Transaction Gains (Losses)

Foreign currency translations and transaction losses for the year ended December 31, 2014 were $5.8 million, compared to gains of $5.1 million for the year ended December 31, 2013. The loss in 2014 was primarily due to foreign currency forward contracts that we entered into to hedge our exposure to the NIS for the year ended December 31, 2014, which were not accounted for as hedge transactions.

Income Attributable to Sale of Tax Benefits

Income attributable to the sale of tax benefits to institutional equity investors (as described in "OPC Transaction" and "ORTP Transaction" each below) for the year ended December 31, 2014 was $24.1 million, compared to $19.9 million for the year ended December 31, 2013. This income represents the value of PTCs and taxable income or loss generated by OPC and ORTP and allocated to investors in the amount of $7.0 million and $17.1 million, respectively, in the year ended December 31, 2014, compared to $5.4 million and $14.5 million, respectively, in the year ended December 31, 2013. The increase was primarily attributable to an additional payment we received in the first quarter of 2014, in the amount of $2.2 million related to the ORTP transaction which represented 25% of the value of PTCs generated.

Gain from sale of Property, Plant and Equipment

Gain from the sale of property, plant and equipment for the year ended December 31, 2014 was $7.6 million. This gain relates to the sale of the Heber Solar project in Imperial County, California for $35.25 million in the first quarter of 2014. We received the first payment of $15.0 million in the first quarter of 2014, and the second payment of the remaining $20.25 million in the second quarter of 2014. We recognized the gain in the second quarter of 2014. There was no gain on the sale of property, plant and equipment in the year ended December 31, 2013.

Income Taxes

Income tax provision for the year ended December 31, 2014 was $27.6 million, compared to $13.6 million for the year ended December 31, 2013. The increase in income tax provision primarily resulted from the increase in income before taxes in jurisdictions outside the U.S.. Our effective tax rate for the years ended December 31, 2014 and 2013, was 32.2% and 26.5%, respectively. The effective tax rate differs from the federal statutory rate of 35% for the year ended December 31, 2014 primarily due to un-benefited losses in the U.S. and certain foreign jurisdictions.

For the year ended December 31, 2014 and 2013, we recorded a valuation allowance in the amount of approximately $111.3 million and $114.8 million respectively, against our U.S. deferred tax assets in respect of net operating loss (NOL) carryforwards and unutilized tax credits (PTCs and ITCs). As of December 31, 2014, we had U.S. federal NOLs in the amount of approximately $237.0 million, state NOLs in the amount of approximately $216.5 million, and unutilized tax credits of approximately $71.4 million, all of which can be carried forward for 20 years. The related deferred tax assets totaled approximately $111.3 million. Realization of these deferred tax assets and tax credits is dependent on generating sufficient taxable income in the U.S. prior to expiration of the NOL carryforwards and tax credits. The scheduled reversal of deferred tax liabilities, projected future taxable income and tax planning strategies were considered in determining the amount of valuation allowance. A valuation allowance in the amount of $111.3 million was recorded against the U.S. deferred tax assets as of December 31, 2014 as at that point in time, we believe it is more likely than not that the deferred tax assets will not be realized. Subsequent to the balance sheet date, and as more fully described in Note 20 of the consolidated financial statements, we entered into a significant non-routine transaction for the partial sale of certain assets which is expected to result in a taxable gain in the U.S., for which we expect to utilize a portion of its NOL carryforwards and tax credits. If sufficient additional evidence of our ability to generate taxable income is established in the future we may be required to reduce or fully release the valuation allowance, resulting in income tax benefits in our consolidated statement of operations.

Equity in losses of investee

Equity in losses of investee in the year ended December 31, 2014 was $3.2 million, compared to $0.3 million in the year ended December 31, 2013. Equity in losses of investee derived from our 12.75% ownership of the Sarulla project.

Income from Continuing Operations

Income from continuing operations for the year ended December 31, 2014 was $55.0 million, compared to $37.3 million for the year ended December 31, 2013, representing an increase of 47.4% from the prior period. The increase in income from continuing operations of $17.7 million was principally attributable to (i) a $46.5 million increase in operating income; (ii) a $7.6 million gain on the sale of property, plant and equipment; and (iii) a $4.2 million increase in income attributable to the sale of tax benefits all as discussed above. This increase was partially offset by (i) a $10.9 million increase in interest expense, net; (ii) a $10.9 million increase in foreign currency translation and transaction losses; and (iii) a $14.1 million increase in income tax provision.

Discontinued Operations

In June 2013, our wholly-owned subsidiary sold its interest in MPC, the operator of the Momotombo geothermal power plant in Nicaragua to a private company for $7.8 million, approximately one year before the scheduled termination of the concession agreement with the Nicaraguan owner. As a result, we recorded an after-tax gain on sale of $3.6 million in the year ended December 31, 2013. MPC operations for the year ended December 31, 2013, were included in discontinued operations. Discontinued operations for the year ended December 31, 2013 include revenues of $4.9 million from MPC.

Net Income

Net income for the year ended December 31, 2014 was $55.0 million, compared to $42.0 million for the year ended December 31, 2013, representing a 30.9% increase from the prior period. The increase in net income was primarily attributable to the increase in income from continuing operations, as discussed above.

Liquidity and Capital Resources

Our principal sources of liquidity have been derived from cash flows from operations, proceeds from third party debt in the form of borrowings under credit facilities and private offerings, issuances of notes, project financing, tax monetization transactions, short term borrowing under our lines of credit, sale of membership interests in one or more of our projects and cash grants we received under the ARRA. We have utilized this cash to develop and construct power generation plants, fund our acquisitions, pay down existing outstanding indebtedness, and meet our other cash and liquidity needs.

As of December 31, 2015, we had access to the following sources of funds: (i) $185.9 million in cash, cash equivalents of which $170.7 million is related to foreign jurisdictions; and (ii) $145.3 million of unused corporate borrowing capacity under existing lines of credit with different commercial banks.

Our estimated capital needs for 2016 include approximately $304.0 million for capital expenditures on new projects under development or construction, exploration activity, operating projects, and machinery and equipment including $35.6 million expected investments in activities under our new strategy plan, as well as $62.7 million for debt repayment.

We expect to finance these requirements with: (i) the sources of liquidity described above; (ii) positive cash flows from our operations; and (iii) future project financing and refinancing (including construction loans). Management believes that based on current stage of implementation of the new strategy plan, they do not see current impact on liquidity and capital resources and these sources will address our anticipated liquidity, capital expenditures, and other investment requirements.

We believe that based on our plans to increase our operations outside of the U.S., the cash generated from our operations outside of the U.S. will be reinvested outside of the U.S. In addition, our U.S. sources of cash and liquidity are sufficient to meet our needs in the U.S., and accordingly, we do not currently plan to repatriate the funds we have designated as being permanently invested outside the U.S. If we change our plans, we may be required to accrue and pay U.S. taxes to repatriate these funds.

Third-Party Debt

Our third-party debt is composed of two principal categories. The first category consists of project finance debt or acquisition financing that we or our subsidiaries have incurred for the purpose of developing and constructing, refinancing or acquiring our various projects, which are described below under “Non-Recourse and Limited-Recourse Third-Party Debt”. The second category consists of debt incurred by us or our subsidiaries for general corporate purposes, which are described below under “Full-Recourse Third-Party Debt.”

Non-Recourse and Limited-Recourse Third-Party Debt

OFC Senior Secured Notes — Non-Recourse

In February 2004, OFC issued $190.0 million of OFC Senior Secured Notes for the purpose of refinancing the acquisition cost of the Brady, Ormesa and Steamboat 1, 1A, 2 and 3 power plants, and the financing of the acquisition cost of 50% of the Mammoth complex. The OFC Senior Secured Notes have a final maturity date of December 30, 2020. Principal and interest on the OFC Senior Secured Notes are payable in semi-annual payments. The OFC Senior Secured Notes are collateralized by substantially all of the assets of OFC and those of its wholly owned subsidiaries and are fully and unconditionally guaranteed by all of the wholly owned subsidiaries of OFC. There are various restrictive covenants under the OFC Senior Secured Notes, which include limitations on additional indebtedness of OFC and its wholly owned subsidiaries. Failure to comply with these and other covenants will, subject to customary cure rights, constitute an event of default by OFC. In addition, there are restrictions on the ability of OFC to make distributions to its shareholders, which include a required historical and projected 12-month debt service coverage ratio (DSCR) of not less than 1.25 (measured semi-annually as of June 30 and December 31 of each year). If OFC fails to comply with the DSCR ratio it will be prohibited from making distributions to its shareholders. We are only required to measure these covenants on a semi-annual basis and as of December 31, 2015, the last measurement date, the actual historical 12-month DSCR was 1.30 and the pro-forma 12-month DSCR was 1.28 (on a semi-annual basis and as of December 31, 2015). There was $30.0 million aggregate principal amount of OFC Senior Secured Notes outstanding as of December 31, 2015.

In June 2015, we repurchased from the OFC noteholders $30.6 million aggregate principal amount of our OFC Senior Secured Notes, which resulted in approximately $2.5 million savings in interest expense. We recognized a loss of approximately $1.7 million in the year ended December 31, 2015, as a result of the repurchase. In January 2014, we repurchased from the OFC noteholders $13.2 million aggregate principal amount of our OFC Senior Secured Notes. We recognized a gain of approximately $0.3 million in the year ended December 31, 2014.

OrCal Geothermal Senior Secured Notes — Non-Recourse

In December, 2005, OrCal issued $165.0 million of OrCal Senior Secured Notes for the purpose of refinancing the acquisition cost of the Heber complex. At closing, the OrCal Senior Secured Notes were rated BBB- by Fitch Ratings. The OrCal Senior Secured Notes have a final maturity date of December 30, 2020. Principal and interest on the OrCal Senior Secured Notes are payable in semi-annual payments. The OrCal Senior Secured Notes are collateralized by substantially all of the assets of OrCal and those of its wholly owned subsidiaries and are fully and unconditionally guaranteed by all of the wholly owned subsidiaries of OrCal. There are various restrictive covenants under the OrCal Senior Secured Notes which include limitations on additional indebtedness of OrCal and its wholly owned subsidiaries. Failure to comply with these and other covenants will, subject to customary cure rights, constitute an event of default by OrCal. In addition, there are restrictions on the ability of OrCal to make distributions to its shareholders, which include a required historical and projected 12-month DSCR of not less than 1.25 (measured semi-annually as of June 30 and December 31 of each year). If OrCal fails to comply with the DSCR ratio it will be prohibited from making distributions to its shareholders. As of December 31, 2015, the last measurement date, the actual historical 12-month DSCR was 1.37, and the pro-forma 12-months DSCR was 1.89. There was $43.3 million aggregate principal amount of OrCal Senior Secured Notes outstanding as of December 31, 2015.

OFC 2 Senior Secured Notes — Limited Recourse during Construction and Non-Recourse Thereafter

In September 2011, OFC 2 and its wholly owned project subsidiaries (collectively, the OFC 2 Issuers) entered into a note purchase agreement (the Note Purchase Agreement) with OFC 2 Noteholder Trust, as purchaser, John Hancock, as administrative agent, and the DOE, as guarantor, in connection with the offer and sale of up to $350.0 million aggregate principal amount of OFC 2 Senior Secured Notes due December 31, 2034. As of December 31, 2015, we have sold $291.7 million of OFC 2 Senior Secured Notes and we do not expect further drawdowns under this agreement.

Subject to the fulfillment of customary and other specified conditions precedent, the OFC 2 Senior Secured Notes may be issued in up to six distinct series associated with the phased construction (Phase I and Phase II) of the Jersey Valley, McGinness Hills and Tuscarora geothermal power plants, which are owned by the OFC 2 Issuers. The OFC 2 Senior Secured Notes will mature and the principal amount of the OFC 2 Senior Secured Notes will be payable in equal quarterly installments and in any event not later than December 31, 2034. Each series of notes will bear interest at a rate calculated based on a spread over the Treasury yield curve that will be set at least ten business days prior to the issuance of such series of notes. Interest will be payable quarterly in arrears. The DOE guarantees payment of 80% of principal and interest on the OFC 2 Senior Secured Notes pursuant to Section 1705 of Title XVII of the Energy Policy Act of 2005, as amended. The conditions precedent to the issuance of the OFC 2 Senior Secured Notes include certain specified conditions required by the DOE in connection with its guarantee of the OFC 2 Senior Secured Notes.

In October 2011, the OFC 2 Issuers completed the sale of $151.7 million aggregate principal amount of 4.687% Series A Notes due 2032 (the Series A Notes). The net proceeds from the sale of the Series A Notes, after deducting transaction fees and expenses, were approximately $141.1 million, and were used to finance a portion of the construction costs of Phase I of the McGinness Hills and Tuscarora power plants and to fund certain reserves. Principal and interest on the Series A Notes are payable quarterly in arrears on the last day of March, June, September and December of each year.

On June 20, 2014, Phase I of the Tuscarora facility achieved project completion under the OFC 2 Note Purchase Agreement. In accordance with the terms of the Note Purchase Agreement, we recalibrated the original financing assumptions and as a result the loan amount was adjusted through a principal payment of $4.3 million.

On August 29, 2014, OFC 2 sold $140.0 million of OFC 2 Senior Secured Notes to finance the construction of the McGinness Hills Phase 2 project. This draw is the last tranche (Series C notes) under the Note Purchase Agreement with John Hancock Life Insurance Company (USA) and is guaranteed by the U.S. DOE Loan Programs Office in accordance with and subject to the DOE's Loan Guarantee Program under section 1705 of Title XVII of the Energy Policy Act of 2005. The $140.0 million loan, which matures in December 2032, carries a 4.61% coupon with principal to be repaid on a quarterly basis. The OFC 2 Senior Secured Notes, which include loans for the Tuscarora, Jersey Valley and McGinness Hills complexes, are rated "BBB" by Standard & Poor's.

In connection with the anticipated drawdown, on August 13, 2014, we entered into an on-the-run interest lock agreement with a financial institution that terminated on August 15, 2014. This on-the-run interest lock agreement had a notional amount of $140.0 million and was designated by us to as a cash flow hedge. The objective of this cash flow hedge was to eliminate the variability in the change in the 10-year U.S. Treasury rate as that is one of the components of the annual interest rate of the OFC 2 loan that was forecasted to be fixed on August 15, 2014. As such, we hedged the variability in total proceeds attributable to changes in the 10-years U.S. Treasury rate for the forecasted issuance of a fixed rate OFC 2 loan. On the settlement date of August 18, 2014, we paid $1.5 million to the counterparty of the on-the-run interest rate lock agreement.

The OFC 2 Senior Secured Notes are collateralized by substantially all of the assets of OFC 2 and those of its wholly owned subsidiaries and are fully and unconditionally guaranteed by all of the wholly owned subsidiaries of OFC 2. There are various restrictive covenants under the OFC 2 Senior Secured Notes, which include limitations on additional indebtedness of OFC 2 and its wholly owned subsidiaries. Failure to comply with these and other covenants will, subject to customary cure rights, constitute an event of default by OFC 2. In addition, there are restrictions on the ability of OFC 2 to make distributions to its shareholders. Among other things, the distribution restrictions include a historical and projected quarterly DSCR requirement of at least 1.2 (on a blended basis for all of the OFC 2 power plants) and 1.5 on a pro forma basis (giving effect to the distributions). We are required to measure these covenants on a quarterly basis and as of December 31, 2015, the last measurement date, the actual DSCR was 1.70 and the pro-forma 12-month DSCR was 2.28. There was $262.0 million aggregate principal amount of OFC 2 Senior Secured Notes outstanding as of December 31, 2015.

We provided a guarantee in connection with the issuance of the Series A Notes, and will provide a guarantee in connection with the issuance of each other Series of OFC 2 Senior Secured Notes, which will be available to be drawn upon if certain trigger events occur. One trigger event is the failure of any facility financed by the relevant series of OFC 2 Senior Secured Notes to reach completion and meet certain operational performance levels (the non-performance trigger) which gives rise to a prepayment obligation on the OFC 2 Senior Secured Notes. The other trigger event is a payment default on the OFC 2 Senior Secured Notes or the occurrence of certain fundamental defaults that result in the acceleration of the OFC 2 Senior Secured Notes, in each case that occurs prior to the date that the relevant facility financed by such OFC 2 Senior Secured Notes reaches completion and meets certain operational performance levels. A demand on our guarantee based on the non-performance trigger is limited to an amount equal to the prepayment amount on the OFC 2 Senior Secured Notes necessary to bring the OFC 2 Issuers into compliance with certain coverage ratios. A demand on our guarantee based on the other trigger event is not so limited.

Olkaria III Finance Agreement with OPIC — Limited Recourse during Construction and Non-Recourse Thereafter

In August 2012, OrPower 4 entered into a finance agreement with OPIC, an agency of the U.S. government, to provide limited-recourse senior secured debt financing in an aggregate principal amount of up to $310.0 million (the OPIC Loan) for the refinancing and financing of our Olkaria III geothermal power complex in Kenya. The finance agreement was amended on November 9, 2012.

The OPIC Loan is comprised of three tranches:

- Tranche I in an aggregate principal amount of $85.0 million, which was drawn in November 2012, was used to prepay approximately $20.5 million (plus associated prepayment penalty and breakage costs of $1.5 million) of the DEG Loan, as described below under “Full Recourse Debt”. The remainder of Tranche I proceeds was used for reimbursement of prior capital costs and other corporate purposes.

- Tranche II in an aggregate principal amount of $180.0 million was used to fund the construction and well field drilling for Plant 2 of the Olkaria III geothermal power complex. In November 2012, an amount of $135.0 million was disbursed under this Tranche II, and in February 2013, the remaining $45.0 million was distributed under this Tranche II.

- Tranche III in an aggregate principal amount of $45.0 million was used to fund the construction of Plant 3 of the Olkaria III geothermal power complex and was drawn down in full in November 2013.

In July 2013, we completed the conversion of the interest rate applicable to both Tranche I and Tranche II from a floating interest rate to a fixed interest rate. The average fixed interest rate for Tranche I, which has an outstanding balance of $70.8 million and matures on December 15, 2030 and Tranche II, which has an outstanding balance of $153.5 million and matures on June 15, 2030, is 6.31%. In November 2013, we fixed the interest rate applicable to Tranche III. The fixed interest rate for Tranche III, which has an outstanding balance of $40.3 million and matures on December 15, 2030, is 6.12%.

OrPower 4 has a right to make voluntary prepayments of all or a portion of the OPIC Loan subject to prior notice, minimum prepayment amounts, and a prepayment premium of 2% in the first two years after the Plant 2 commercial operation date, declining to 1% in the third year after the Plant 2 commercial operation date, and without premium thereafter, plus a redemption premium. In addition, the OPIC Loan is subject to customary mandatory prepayment in the event of certain reductions in generation capacity of the power plants, unless such reductions will not cause the projected ratio of cash flow to debt service to fall below 1.7.

The OPIC Loan is secured by substantially all of OrPower 4’s assets and by a pledge of all of the equity interests in OrPower 4.

The finance agreement includes customary events of default, including failure to pay any principal, interest or other amounts when due, failure to comply with covenants, breach of representations and warranties, non-payment or acceleration of other debt of OrPower 4, bankruptcy of OrPower 4 or certain of its affiliates, judgments rendered against OrPower 4, expropriation, change of control, and revocation or early termination of security documents or certain project-related agreements, subject to various exceptions and notice, cure and grace periods.

The repayment of the remaining outstanding DEG Loan (see “Full-Recourse Third-Party Debt” below) in the amount of approximately $23.7 million as of December 31, 2015, has been subordinated to the OPIC Loan.

There are various restrictive covenants under the OPIC Loan, including a required historical and projected 12-month DSCR of not less than 1.4 (measured as of March 15, June 15, September 15 and December 15 of each year). If

OrPower 4 fails to comply with these financial covenants it will be prohibited from making distributions to its shareholders. In addition, if the DSCR falls below 1.1, subject to certain cure rights such failure will constitute an event of default by OrPower 4. This covenant in respect of Tranche I became effective on December 15, 2014. As of December 31, 2015, the actual historical and projected 12-month DSCR was 2.23 and 2.62, respectively.

As of December 31, 2015, \$264.6 million of the OPIC Loan was outstanding.

Amatitlan Loan — Non-Recourse

On July 31, 2015 Ortitl n, Limitada, obtained a 12-year secured term loan in the principal amount of \$42.0 million for the 20 MW Amatitlan power plant in Guatemala. Under the credit agreement with Banco Industrial S.A. and Westrust Bank (International) Limited, we can expand the Amatitlan power plant with financing to be provided either via equity, additional debt from Banco Industrial S.A. or from other lenders, subject to certain limitations on expansion financing in the credit agreement.

The loan is payable in 48 quarterly payments commencing September 30, 2015. The loan bears interest at a rate *per annum* equal to the sum of the LIBO Rate (which cannot be lower than 1.25%) plus a margin of (i) 4.35% as long as the Company's guaranty of the loan (as described below) is outstanding or (ii) 4.75% otherwise. Interest is payable quarterly, on March 30, June 30, September 30 and December 30 of each year, on the stated maturity date of the loan and on any prepayment or payment of the loan. The loan must be prepaid upon the occurrence of certain events, such as casualty, condemnation, asset sales and expansion financing not provided by the lenders under the credit agreement, among others. The loan may be voluntarily prepaid if certain conditions are satisfied, including payment of a premium (ranging from 100-50 basis points) if prepayment occurs prior to the eighth anniversary of the loan.

There are various restrictive covenants under the Amatitlan credit agreement. These include, among others, (i) a financial covenant to maintain a Debt Service Coverage Ratio (as defined in the credit agreement) of not less than 1.15 to 1.00 as of the last day of any fiscal quarter and (ii) limitations on Restricted Payments (as defined in the credit agreement) that among other things would limit dividends that could be paid to us unless the historical and projected Debt Service Coverage Ratio is not less than 1.25 to 1.00 for the four fiscal quarterly periods (calculated as a single accounting period). As of December 31, 2015, the actual historical and projected 12-month Debt Service Coverage Ratio was 1.84 and 2.00, respectively. The credit agreement includes various events of default that would permit acceleration of the loan (subject in some cases to grace and cure periods). These include, among others, a Change of Control (as defined in the credit agreement) and failure to maintain certain required balances in debt service and maintenance reserve accounts. The credit agreement includes certain equity cure rights for failure to maintain the Debt Service Coverage Ratio and the minimum amounts required in the debt service and maintenance reserve accounts.

The loan is secured by substantially all the assets of the borrower and a pledge of all of the membership interests of the borrower.

The Company has guaranteed payment of all obligations under the credit agreement and related financing documents. The guaranty is limited in the sense that the Company is only required to pay the guaranteed obligations if a “trigger event” occurs. A trigger event is the occurrence and continuation of a default by INDE in its payment obligations under the power purchase agreement for the Amatitlàn power plant or a refusal by INDE to receive capacity and energy sold under that power purchase agreement. Our obligations under the guaranty may be terminated prior to payment in full of the guaranteed obligations under certain circumstances described in the guaranty. If our guaranty is terminated early, the interest rate payable on the loan would increase as described above.

As of December 31, 2015, $40.3 million of this loan is outstanding.

Full-Recourse Third-Party Debt

Union Bank. In February 2012, Ormat Nevada entered into an amended and restated credit agreement with Union Bank. Under the amended and restated agreement, the credit termination date was extended from February 15, 2012 to February 7, 2014, and was subsequently extended to May 20, 2015, and then June 30, 2016. The aggregate amount available under the credit agreement is $50.0 million. The facility is limited to the issuance, extension, modification or amendment of letters of credit. Union Bank is currently the sole lender and issuing bank under the credit agreement, but is also designated as an administrative agent on behalf of banks that may, from time to time in the future, join the credit agreement as lenders. In connection with this transaction, we entered into a guarantee in favor of the administrative agent for the benefit of the banks, pursuant to which we agreed to guarantee Ormat Nevada’s obligations under the credit agreement. Ormat Nevada’s obligations under the credit agreement are otherwise unsecured.

There are various restrictive covenants under the credit agreement, including a requirement to comply with the following financial ratios, which are measured quarterly: (i) a 12-month debt to EBITDA ratio not to exceed 4.5; (ii) 12-month DSCR of not less than 1.35; and (iii) distribution leverage ratio not to exceed 2.0. As of December 31, 2015: (i) the actual 12-month debt to EBITDA ratio was 2.58; (ii) the 12-month DSCR was 2.39; and (iii) the distribution leverage ratio was 0.53. In addition, there are restrictions on dividend distributions in the event of a payment default or noncompliance with such ratios, and subject to specified carve-outs and exceptions, a negative pledge on the assets of Ormat Nevada in favor of Union Bank.

As of December 31, 2015, letters of credit in the aggregate amount of $43.6 million remain issued and outstanding under this committed credit agreement with Union Bank.

HSBC. In May 2013, Ormat Nevada entered into a credit agreement with HSBC Bank USA, N.A for one year with annual renewals, which was subsequently extended to May 31, 2015, and then June 30, 2016. The aggregate amount available under the credit agreement is $25.0 million. This credit line is limited to the issuance, extension, modification or amendment of letters of credit and $10.0 million out of this credit line is available to be drawn for working capital needs. HSBC is currently the sole lender and issuing bank under the credit agreement, but is also designated as an administrative agent on behalf of banks that may, from time to time in the future, join the credit agreement as lenders. In connection with this transaction, we entered into a guarantee in favor of the administrative agent for the benefit of the banks, pursuant to which we agreed to guarantee Ormat Nevada’s obligations under the credit agreement. Ormat Nevada’s obligations under the credit agreement are otherwise unsecured.

There are various restrictive covenants under the credit agreement, including a requirement to comply with the following financial ratios, which are measured quarterly: (i) a 12-month debt to EBITDA ratio not to exceed 4.5; (ii) 12-month DSCR of not less than 1.35; and (iii) distribution leverage ratio not to exceed 2.0. As of December 31, 2015: (i) the actual 12-month debt to EBITDA ratio was 2.58; (ii) the 12-month DSCR was 2.39; and (iii) the distribution leverage ratio was 0.53. In addition, there are restrictions on dividend distributions in the event of a payment default or noncompliance with such ratios, and subject to specified carve-outs and exceptions, a negative pledge on the assets of Ormat Nevada in favor of HSBC.

As of December 31, 2015, letters of credit in the aggregate amount of $25.0 million remain issued and outstanding under this committed credit agreement.

Credit Agreements. We also have committed credit agreements with five other commercial banks for an aggregate amount of $457.5 million. Under the terms of these credit agreements, we or our Israeli subsidiary, Ormat Systems, can request: (i) extensions of credit in the form of loans and/or the issuance of one or more letters of credit in the amount of up to $237.0 million; and (ii) the issuance of one or more letters of credit in the amount of up to $220.5 million. The credit agreements mature at the end of February 2016 and November 2016. Loans and draws under the credit agreements or under any letters of credit will bear interest at the respective bank's cost of funds plus a margin.

As of December 31, 2015, letters of credit with an aggregate stated amount of $318.6 million were issued and outstanding under these credit agreements.

Term Loans. We had a $20.0 million term loan with a group of institutional investors, which matured on July 16, 2015, that was payable in 12 semi-annual installments commencing January 16, 2010, and bore interest of 6.5%. As of December 31, 2015, this loan was fully repaid.

We have a $20.0 million term loan with a group of institutional investors, which matures on August 1, 2017, is payable in 12 semi-annual installments commencing February 1, 2012, and bears interest at 6-month LIBOR plus 5.0%. As of December 31, 2015, $6.7 million was outstanding under this loan.

We had a $20.0 million term loan with a group of institutional investors. In October 2015 we prepaid in full the outstanding principal of the loan in accordance with the loan's prepayment provisions. The loan was payable in ten semi-annual installments commencing May 16, 2012, and bore interest of 5.75%.

Senior Unsecured Bonds. Approximately $250.0 million aggregate principal amount of our Senior Unsecured Bonds are issued and outstanding. We issued approximately $142.0 million of these bonds in August 2010 and an additional $107.5 million in February 2011. Subject to early redemption, principal is repayable in a single bullet payment upon the final maturity of the bonds on August 1, 2017. The bonds bear interest at a fixed rate of 7.00%, payable semi-annually. The bonds that we issued in February 2011 were issued at a premium which reflects an effective fixed interest of 6.75%.

Loan Agreement with DEG (The Olkaria III Complex). OrPower 4 entered into a project financing loan to refinance its investment in Plant 1 of the Olkaria III complex located in Kenya with a group of European DFIs arranged by DEG.

The DEG Loan will mature on December 15, 2018, and is payable in 19 equal semi-annual installments. Interest on the loan is variable based on 6-month LIBOR plus 4.0%. We fixed the interest rate on most of the loan at 6.90%. As of December 31, 2015, $23.7 million is outstanding under the DEG Loan (out of which $21.7 million bears interest at a fixed rate).

In October 2012, OrPower 4, DEG and the other parties thereto amended and restated the DEG Loan Agreement. The amendment became effective on November 9, 2012 upon the execution by OrPower 4 of the Tranche I and Tranche II Notes under the OPIC loan and the related disbursements of the proceeds thereof under the OPIC Finance Agreement (as described above under the heading “Non-Recourse and Limited –Recourse Third-Party Debt”). As part of the amendment we prepaid in full two loans under the DEG facility with an aggregate principal amount of approximately $20.5 million. The amended and restated DEG Loan Agreement provides for (i) the release and discharge of all collateral security previously provided by OrPower 4 to the secured parties under the DEG Loan Agreement and the substitution of the Company’s guarantee of OrPower 4’s payment and certain other performance obligations in lieu thereof; (ii) the establishment of a LIBOR floor of 1.25% in respect of one of the loans under the DEG Loan Agreement, and (iii) the elimination of most of the affirmative and negative covenants under the DEG Loan Agreement and certain other conforming provisions as a result of OrPower 4’s execution of the OPIC Finance Agreement and its obligations thereunder.

Our obligations under the credit agreements, the loan agreements, and the trust instrument governing the bonds described above, are unsecured, but we are subject to a negative pledge in favor of the banks and the other lenders and certain other restrictive covenants. These include, among other things, a prohibition on: (i) creating any floating charge or any permanent pledge, charge or lien over our assets without obtaining the prior written approval of the lender; (ii) guaranteeing the liabilities of any third party without obtaining the prior written approval of the lender; and (iii) selling, assigning, transferring, conveying or disposing of all or substantially all of our assets, or a change of control in our ownership structure. Some of the credit agreements, the term loan agreements, and the trust instrument contain cross-default provisions with respect to other material indebtedness owed by us to any third party. In some cases, we have agreed to maintain certain financial ratios, which are measured quarterly, such as: (i) equity of at least $600 million and in no event less than 30% of total assets; (ii) 12-month debt, net of cash, cash equivalents, and short-term bank deposits to Adjusted EBITDA ratio not to exceed 7.0; and (iii) dividend distributions not to exceed 35% of net income in any calendar year. As of December 31, 2015: (i) total equity was $1083.9 million and the actual equity to total assets ratio was 47.3 and (ii) the 12-month debt, net of cash, cash equivalents, to Adjusted EBITDA ratio was 2.63. During the year ended December 31, 2015, we distributed interim dividends in an aggregate amount of $12.7 million. The failure to perform or observe any of the covenants set forth in such agreements, subject to various cure periods, would result in the occurrence of an event of default and would enable the lenders to accelerate all amounts due under each such agreement.

As described above, we are currently in compliance with our covenants with respect to the credit agreements, the loan agreements and the trust instrument, and believe that the restrictive covenants, financial ratios and other terms of any of our (or Ormat Systems') full-recourse bank credit agreements will not materially impact our business plan or operations.

Letters of Credit

Some of our customers require our project subsidiaries to post letters of credit in order to guarantee their respective performance under relevant contracts. We are also required to post letters of credit to secure our obligations under various leases and licenses and may, from time to time, decide to post letters of credit in lieu of cash deposits in reserve accounts under certain financing arrangements. In addition, our subsidiary, Ormat Systems, is required from time to time to post performance letters of credit in favor of our customers with respect to orders of products.

As of December 31, 2015, committed letters of credit in the aggregate amount of $399.1 million remained issued and outstanding under the credit agreements with Union Bank, HSBC and five of the commercial banks as described under "Full-Recourse Third Party Debt".

Puna Power Plant Lease Transactions

In May 2005, our Hawaiian subsidiary, PGV, entered into a transaction involving the original geothermal power plant of the Puna complex located on the Big Island. The transaction was concluded with financing parties by means of a leveraged lease transaction. A secondary stage of the lease transaction relating to two new geothermal wells that PGV drilled in the second half of 2005 (for production and injection) was completed on December 30, 2005. Pursuant to a 31-year head lease, PGV leased its geothermal power plant to the previously mentioned financing parties in return for payments of $83.0 million by such financing parties to PGV, which are accounted for as deferred lease income.

OPC Transaction

In June 2007, Ormat Nevada entered into agreements with affiliates of Morgan Stanley & Co. Incorporated and Lehman Brothers Inc. (Morgan Stanley Geothermal LLC and Lehman-OPC LLC, respectively), under which those investors purchased, for cash, interests in a newly formed subsidiary of Ormat Nevada, OPC, entitling the investors to certain tax benefits (such as PTCs and accelerated depreciation) and distributable cash associated with four geothermal power plants in Nevada.

The first closing under the agreements occurred in 2007 and covered our Desert Peak 2, Steamboat Hills, and Galena 2 power plants. The investors paid $71.8 million at the first closing. The second closing under the agreements occurred in 2008 and covered the Galena 3 power plant. The investors paid $63.0 million at the second closing.

Ormat Nevada continues to operate and maintain the power plants. Under the agreements, Ormat Nevada initially received all of the distributable cash flow generated by the power plants, while the investors received substantially all of the PTCs and the taxable income or loss (together, the Economic Benefits). Once Ormat Nevada recovered the capital that it invested in the power plants, which occurred in the fourth quarter of 2010, the investors began receiving both the distributable cash flow and the Economic Benefits. Once the investors reach a target after-tax yield on their investment in OPC (the OPC Flip Date), Ormat Nevada will receive 95% of both distributable cash and taxable income, on a going forward basis. Following the OPC Flip Date, Ormat Nevada also has the option to purchase the investors' remaining interest in OPC at the then-current fair market value or, if greater, the investors' capital account balances in OPC. If Ormat Nevada were to exercise this purchase option, it would become the sole owner of the power plants again.

Our voting rights in OPC are based on a capital structure that is comprised of Class A and Class B membership units. Through Ormat Nevada, we own all of the Class A membership units, which represent 75% of the voting rights in OPC and the investors(as described below) own all of the Class B membership units, which represent 25% of the voting rights of OPC. Other than in respect of customary protective rights, all operational decisions in OPC are decided by the vote of a majority of the membership units. Following the OPC Flip Date, Ormat Nevada’s voting rights will increase to 95% and the investor’s voting rights will decrease to 5%. Ormat Nevada retains the controlling voting interest in OPC both before and after the OPC Flip Date and therefore consolidates OPC.

The Class B membership units are provided with a 5% residual economic interest in OPC, which commences as of the OPC Flip Date. This residual 5% interest represents a noncontrolling interest and is not subject to mandatory redemption or guaranteed payments. The Class B membership units are currently held by Morgan Stanley Geothermal LLC and JPM. On October 30, 2009, Ormat Nevada acquired from Lehman-OPC LLC all of the Class B membership units of OPC held by Lehman-OPC LLC pursuant to a right of first offer for a purchase price of $18.5 million in cash and on February 3, 2011, Ormat Nevada sold to JPM all of the Class B membership units of OPC that it had acquired for a sale price of $24.9 million in cash.

ORTP Transaction

On January 24, 2013, Ormat Nevada entered into agreements with JPM under which JPM purchased interests in a newly formed subsidiary of Ormat Nevada, ORTP, entitling JPM to certain tax benefits (such as PTCs and accelerated depreciation) associated with certain geothermal power plants in California and Nevada.

Under the terms of the transaction, Ormat Nevada transferred the Heber complex, the Mammoth complex, the Ormesa complex, and the Steamboat 2 and 3, Burdette (Galena 1) and Brady power plants to ORTP, and sold Class B membership units in ORTP to JPM. In connection with the closing, JPM paid approximately $35.7 million to Ormat Nevada and will make additional payments to Ormat Nevada of 25% of the value of PTCs generated by the portfolio over time. The additional payments are expected to be made until December 31, 2016 and total up to a maximum amount of $11.0 million, of which we received $2.0 million and $1.6 million in the first quarters of 2016 and 2015, respectively.

Ormat Nevada will continue to operate and maintain the power plants. Under the agreements, Ormat Nevada will initially receive all of the distributable cash flow generated by the power plants, while JPM will receive substantially all of PTCs and the taxable income or loss (together, the Economic Benefits). JPM’s return is limited by the terms of the transaction. Once JPM reaches a target after-tax yield on its investment in ORTP (the ORTP Flip Date), Ormat Nevada will receive 97.5% of the distributable cash and 95.0% of the taxable income, on a going forward basis. At any time during the twelve-month period after the end of the fiscal year in which the ORTP Flip Date occurs (but no earlier than the expiration of five years following the date that the last of the power plants was placed in service for purposes of federal income taxes), Ormat Nevada also has the option to purchase JPM’s remaining interest in ORTP at the then-current fair market value. If Ormat Nevada were to exercise this purchase option, it would become the sole owner of the power plants again.

The Class B membership units entitle the holder to a 5.0% (allocation of income and loss) and 2.5% (allocation of cash) residual economic interest in ORTP. The 5.0% and 2.5% residual interests commence on achievement by JPM of a contractually stipulated return that triggers the ORTP Flip Date. The actual ORTP Flip Date is not known with certainty. These residual 5.0% and 2.5% interests represent noncontrolling interests and are not subject to mandatory redemption or guaranteed payments.

Our voting rights in ORTP are based on a capital structure that is comprised of Class A and Class B membership units. Through Ormat Nevada, we own all of the Class A membership units, which represent 75.0% of the voting rights in ORTP. JPM owns all of the Class B membership units, which represent 25.0% of the voting rights of ORTP. Other than in respect of customary protective rights, all operational decisions in ORTP are decided by the vote of a majority of the membership units. Ormat Nevada retains the controlling voting interest in ORTP both before and after the ORTP Flip Date and therefore will continue to consolidate ORTP.

Liquidity Impact of Uncertain Tax Positions

As discussed in Note 18 to our consolidated financial statements set forth in Item 8 of this annual report, we have a liability associated with unrecognized tax benefits and related interest and penalties in the amount of approximately $10.4 million as of December 31, 2015. This liability is included in long-term liabilities in our consolidated balance sheet, because we generally do not anticipate that settlement of the liability will require payment of cash within the next twelve months. We are not able to reasonably estimate when we will make any cash payments required to settle this liability.

Dividend

The following are the dividends declared by us during the past two years:

Date Declared	**Dividend Amount per Share**	**Record Date**	**Payment Date**
November 6, 2013	$ 0.04	November 20, 2013	December 4, 2013
February 25, 2014	$ 0.06	March 13, 2014	March 27, 2014
May 8, 2014	$ 0.05	May 21, 2014	May 30, 2014
August 5, 2014	$ 0.05	August 19, 2014	August 28, 2014
November 5, 2014	$ 0.05	November 20, 2014	December 4, 2014
February 24, 2015	$ 0.08	March 16, 2015	March 27, 2015
May 6, 2015	$ 0.06	May 19, 2015	May 27, 2015
August 3, 2015	$ 0.06	August 18, 2015	September 2, 2015
November 3, 2015	$ 0.06	November 18, 2015	December 2, 2015
February 23, 2016	$ 0.31	March 15, 2016	March 29, 2016

Historical Cash Flows

The following table sets forth the components of our cash flows for the relevant periods indicated:

	Year Ended December 31,		
	2015	**2014**	**2013**
	(Dollars in thousands)		
Net cash provided by operating activities	$190,025	$213,235	86,760
Net cash used in investing activities	(90,971)	(129,162)	(157,153)
Net cash provided by (used in) financing activities	46,635	(101,197)	61,119
Net change in cash and cash equivalents	145,689	(17,124)	(9,247)

For the Year Ended December 31, 2015

Net cash provided by operating activities for the year ended December 31, 2015 was $190.0 million, compared to $213.2 million for the year ended December 31, 2014. This decrease of $23.2 million resulted primarily from (i) an increase in receivables of $3.8 million in the year ended December 31, 2015, compared to a decrease of $47.1 million in the year ended December 31, 2014, as a result of timing of collections from our customers; and (ii) a decrease in deferred income tax liabilities of $39.5 million in the year ended December 31, 2015, mainly due to the deferred tax asset in Kenya, as discussed above, compared to an increase of $13.1 million in the year ended December 31, 2014. The decrease was partially offset by the increase in cash inflow due to higher net income of $68.3 million, up from $55.0 million for the year ended December 31, 2014 to $123.3 million for the year ended December 31, 2015 as described above.

Net cash used in investing activities for the year ended December 31, 2015 was $91.0 million, compared to $129.2 million for the year ended December 31, 2014. The principal factors that affected our net cash used in investing activities during the year ended December 31, 2015 were capital expenditures of $152.1 million, primarily for our facilities under construction, reduced by a net decrease of $43.7 million in restricted cash and cash equivalents, due to timing of debt repayments, and $15.4 million derived from cash of Ormat Industries due to the share exchange.

Net cash provided by financing activities for the year ended December 31, 2015 was $46.6 million, compared to $101.2 million used for the year ended December 31, 2014. The principal factors that affected the net cash provided by financing activities during the year ended December 31, 2015 were: net proceeds from issuance of shares to a noncontrolling interest in the amount of $156.5 million and $42.0 million of proceeds from a term loan for our Amatitlan power plant, reduced by: (i) $30.6 million of cash paid to repurchase our OFC Senior Secured Notes; (ii) the repayment of long-term debt in the amount of $71.7 million; (iii) a net decrease of $20.3 million against our revolving credit lines with commercial banks; (iv) $19.1 million of cash paid to noncontrolling interests; and (v) payment of a $12.7 million cash dividend.

For the Year Ended December 31, 2014

Net cash provided by operating activities for the year ended December 31, 2014 was $213.2 million, compared to $86.8 million for the year ended December 31, 2013. This increase of $126.5 million resulted primarily from (i) a decrease in receivables of $47.1 million in the year ended December 31, 2014, compared to an increase of $37.2 million in the year ended December 31, 2013, as a result of timing of collections from our customers; (ii) an increase in billing in excess of costs and estimated earnings on uncompleted contracts, net of $10.2 million in our Product segment in the year ended December 31, 2014, compared to a decrease of $29.1 million in the year ended December 31, 2013, as a result of timing in billing of our customers; and (iii) the increase in cash inflow from higher net income of $13.0 million, from $42.0 million for the year ended December 31, 2013 to $55.0 million for the year ended December 31, 2014.

Net cash used in investing activities for the year ended December 31, 2014 was $129.2 million, compared to $157.2 million for the year ended December 31, 2013. The principal factors that affected our net cash used in investing activities during the year ended December 31, 2014 were: (i) capital expenditures of $151.2 million, primarily for our facilities under construction; and (ii) a net increase of $42.2 million in restricted cash and cash equivalents, due to timing of debt repayments, reduced by: (i) a cash grant of $27.4 million received in the year ended December 31, 2014 from the U.S. Treasury under Section 1603 of the ARRA relating to our Don A. Campbell geothermal power plant and our G1 refurbishment power plant at the Mammoth Complex; and (iii) $35.3 million cash received due to the sale of Heber Solar.

Net cash used in financing activities for the year ended December 31, 2014 was $101.2 million, compared to net cash provided by financing activities of $61.1 million for the year ended December 31, 2013. The principal factors that affected the net cash used in financing activities during the year ended December 31, 2014 were: (i) net repayment of $91.7 million under our revolving credit lines with commercial banks; (ii) the repayment of long-term debt in the amount of $111.2 million; (iii) $12.9 million of cash paid to repurchase our OFC Senior Secured Notes; (iv) $11.4 million of cash paid to a noncontrolling interest; and (v) payment of a $9.6 million cash dividend, reduced by $140.0 million of proceeds from the sale of Series C Senior Secured Notes in August 2014 by OFC2 to finance a portion of the construction costs of Phase 2 of the McGinness Hills facility.

EBITDA and Adjusted EBITDA

We calculate EBITDA as net income before interest, taxes, depreciation and amortization. We calculate Adjusted EBITDA as net income before interest, taxes, depreciation and amortization, adjusted for (i) termination fees, (ii) impairment of long-lived assets, (iii) write-off of unsuccessful exploration activities, (iv) any mark-to-market gains or losses from accounting for derivatives, (v) merger and acquisition transaction costs (vi) stock-based compensation, and (vii) gain from extinguishment of liability. EBITDA and Adjusted EBITDA are not measurements of financial performance or liquidity under accounting principles generally accepted in the United States of America, or U.S.

GAAP, and should not be considered as an alternative to cash flow from operating activities or as a measure of liquidity or an alternative to net earnings as indicators of our operating performance or any other measures of performance derived in accordance with U.S. GAAP. EBITDA and Adjusted EBITDA are presented because we believe they are frequently used by securities analysts, investors and other interested parties in the evaluation of a company's ability to service and/or incur debt. However, other companies in our industry may calculate EBITDA and Adjusted EBITDA differently than we do.

This information should not be considered in isolation from, or as a substitute for, or superior to, measures of financial performance prepared in accordance with GAAP or other non-GAAP financial measures.

Adjusted EBITDA for the year ended December 31, 2015 was $291.3 million, compared to $272.7 million for the year ended December 31, 2014 and $241.0 million for the year ended December 31, 2013.

The following table reconciles net cash provided by operating activities to EBITDA and adjusted EBITDA, for the years ended December 31, 2015, 2014, and 2013:

	Year Ended December 31,		
	2015	**2014**	**2013**
	(in thousands)		
Net cash provided by operating activities	$190,025	$213,235	$86,760
Adjusted for:			
Interest expense, net (excluding amortization of deferred financing costs)	63,802	76,970	67,677
Interest income	(297)	(312)	(1,332)
Income tax provision	(15,258)	27,608	14,166
Minority interest in earnings of subsidiaries Adjustments to reconcile net income to net cash provided by operating activities (excluding depreciation and amortization)	40,530	(57,422)	48,203
EBITDA	278,802	260,079	215,474
Mark to market on derivatives which represent swap contracts on natural gas and oil prices	4,129	(6,960)	7,813
Stock-based compensation	3,955	5,571	6,262
Gain on sale of subsidiary and property, plant and equipment	-	(7,628)	(3,646)
Termination fee	-	-	11,604
Loss from extinguishment of liability	1,710	-	-
Merger and acquisition transaction costs	3,800	1,000	-
Write-off of unsuccessful exploration activities	1,579	15,439	4,094
Mark to market on derivatives which represent currency forward contracts	(2,720)	5,172	(615)
Adjusted EBITDA	$291,255	$272,673	$240,986
Net cash used in investing activities	$(90,971)	$(129,162)	$(157,153)
Net cash used in financing activities	$46,635	$(101,197)	$61,119

Capital Expenditures

Our capital expenditures primarily relate to: (i) the enhancement of our existing power plants; (ii) the development and construction of new power plants; and the investment in new activities under the new strategic plan.

We have estimated approximately $197.0 million in capital expenditures for construction of new projects and enhancements to our existing power plants, of which we have invested approximately $28.8 million as of December 31, 2015. We expect to invest $83.2 million in 2016 and the remaining $85.0 million thereafter.

In addition, we estimate approximately $180.6 million in additional capital expenditures in 2016 to be allocated as follows: (i) $80.9 million for development of new projects; (ii) $31.0 million for maintenance capital expenditures to our operating power plants; (iii) $28.3 million for continued exploration activity under various leases for geothermal resources where we have already started exploration activity; (iv) $35.6 million for investments in new activities that reflects expenditures under the new strategic plan; and (v) $5.0 million for enhancements to our production facilities.

In the aggregate, we estimate our total capital expenditures for 2016 to be approximately $264.0 million.

Based on current conditions, we believe that we have sufficient financial resources to fund our activities and execute our business plans. However, the cost of obtaining financing for our project needs may increase significantly or such financing may be difficult to obtain.

Exposure to Market Risks

We, like other power plant operators, are exposed to electricity price volatility risk. Our exposure to such market risk is currently limited because many of our long-term PPAs (except for the 25 MW PPA for the Puna complex and the aggregate 90 MW PPAs for the Heber 2 power plant in the Heber complex, the Ormesa complex and the G2 power plant in the Mammoth complex) have fixed or escalating rate provisions that limit our exposure to changes in electricity prices. The energy payments under the PPAs of the Heber 2 power plant in the Heber complex, the Ormesa complex and the G2 power plant in Mammoth complex are determined by reference to the relevant power purchaser's SRAC. A decline in the price of natural gas will result in a decrease in the incremental cost that the power purchaser avoids by not generating its electrical energy needs from natural gas, which in turn will reduce the variable energy rate that we may charge under the relevant PPA for these power plants. In October 2013, March 2014, May 2015 and February 2016, we entered into derivative transactions to reduce our exposure to the price of natural gas under these PPAs, until December 29, 2016. The Puna complex is currently benefiting from energy prices which are higher than the floor under the 25 MW PPA for the Puna complex as a result of the high fuel costs that impact HELCO's avoided costs. Similarly, in October 2013 we entered into a derivative transaction to reduce our exposure to the price of oil, under the 25 MW PPA for the Puna complex, until December 31, 2014.

As of December 31, 2015, 94.1% of our consolidated long-term debt was fixed rate debt and therefore was not subject to interest rate volatility risk. As of such date, 5.9% of our long-term debt was floating rate debt, exposing us to interest rate risk in connection therewith. As of December 31, 2015, $54.4 million of our long-term debt remained subject to some interest rate risk.

We currently maintain our surplus cash in short-term, interest-bearing bank deposits, money market securities and commercial paper (with a minimum investment grade rating of AA by Standard & Poor's Ratings Services.

Our cash equivalents are subject to interest rate risk. Fixed rate securities may have their market value adversely impacted by a rise in interest rates, while floating rate securities may produce less income than expected if interest rates fall. As a result of these factors, our future investment income may fall short of expectations because of changes in interest rates, or we may suffer losses in principal if we are forced to sell securities that decline in market value because of changes in interest rates.

We are also exposed to foreign currency exchange risk, in particular the fluctuation of the U.S. dollar versus the NIS. Risks attributable to fluctuations in currency exchange rates can arise when we or any of our foreign subsidiaries borrow funds or incur operating or other expenses in one type of currency but receive revenues in another. In such cases, an adverse change in exchange rates can reduce such subsidiary's ability to meet its debt service obligations, reduce the amount of cash and income we receive from such foreign subsidiary, or increase such subsidiary's overall expenses. Risks attributable to fluctuations in foreign currency exchange rates can also arise when the currency denomination of a particular contract is not the U.S. dollar. Substantially all of our PPAs in the international markets are either U.S. dollar-denominated or linked to the U.S. dollar. Our construction contracts from time to time contemplate costs which are incurred in local currencies. The way we often mitigate such risk is to receive part of the proceeds from the contract in the currency in which the expenses are incurred. Currently, we have forward contracts in place to reduce our foreign currency exposure, and expect to continue to use currency exchange and other derivative instruments to the extent we deem such instruments to be the appropriate tool for managing such exposure. We do not believe that our exchange rate exposure has or will have a material adverse effect on our financial condition, results of operations or cash flows.

We performed a sensitivity analysis on the fair values of our swap contracts on oil prices, put options on natural gas prices, long-term debt obligations, and foreign currency exchange forward contracts. The swap contracts on oil prices, put options on natural gas prices and foreign currency exchange forward contracts listed below principally relate to trading activities. The sensitivity analysis involved increasing and decreasing forward rates at December 31, 2015 and 2014 by a hypothetical 10% and calculating the resulting change in the fair values.

At this time, the development of our new strategic plan has not exposed us to any additional market risk. However, the implementation of the plan progresses, we may be exposed to additional or different market risks.

The results of the sensitivity analysis calculations as of December 31, 2015 and 2014 are presented below:

	Assuming a 10% Increase in Rates		Assuming a 10% Decrease in Rates		
	10% Increase in Rates		10% Decrease in Rates		
	As of December 31,		As of December 31,		
Risk	**2015**	**2014**	**2015**	**2014**	**Change in the Fair Value of**
	(In thousands)				
NGI Price	$-	$(685)	$-	$685	NGI Swap
Foreign Currency	$(3,894)	$(6,720)	$4,760	$1,809	Foreign Currency Forward Contracts
Interest Rate	$(408)	$(1,102)	$417	$1,129	Ormat Funding Corp. ("OFC")
Interest Rate	$(646)	$(921)	$660	$945	Orcal Geothermal Inc. ("OrCal")
Interest Rate	$(9,322)	$(10,155)	$9,941	$10,861	OFC 2 LLC ("OFC 2")
Interest Rate	$(175)	$(244)	$172	$249	Loan from DEG
Interest Rate	$(9,164)	$(10,211)	$9,685	$10,825	Loan from OPIC
Interest Rate	$- (1)	$-	$- (1)	$-	Amatitlan loan
Interest Rate	$(1,888)	$(3,054)	$1,907	$3,099	Senior unsecured bonds

(1) The application of a 10% increase and decrease to the interest rate, did not exceed the minimum rate as set in the credit agreement

Effect of Inflation

We do not expect that inflation will be a significant risk in the near term, given the current global economic conditions, however, that could change in the future. To address rising inflation, some of our contracts include certain provisions that mitigate inflation risk.

In connection with the Electricity segment, inflation may directly impact an expense we incurfor the operation of our projects, thereby increasing our overall operating costs. The negative impact of inflation may be partially offset by price adjustments built into some of our PPAs that could be triggered upon such occurrences. The energy payments pursuant to the PPAs for the Brady power plant, the Steamboat 2 and 3 power plants, the Steamboat Hills power plant, and the Burdette power plant increase every year through the end of the relevant terms of such agreements, though such increases are not directly linked to the CPI or any other inflationary index. Lease payments are generally fixed, while royalty payments are generally calculated as a percentage of revenues and therefore are not significantly impacted by inflation. In our Product segment, inflation may directly impact fixed and variable costs incurred in the construction of our power plants, thereby increasing our operating costs in the Product segment. We are more likely to be able to offset all or part of this inflationary impact through our project pricing. With respect to power plants that we build for our own electricity production, inflationary pricing may impact our operating costs which may be partially offset in the pricing of the new long-term PPAs that we negotiate.

Contractual Obligations and Commercial Commitments

The following tables set forth our material contractual obligations as of December 31, 2015 (in thousands):

Payments Due By Period

Remaining