ORMAT TECHNOLOGIES, INC.
Form 10-K
February 26, 2015

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, 2014
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, 2014, 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 $527,942,658 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 26, 2015, the number of outstanding shares of common stock, par value $0.001 per share was 48,552,560.

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, 2014.

ORMAT TECHNOLOGIES, INC.

FORM 10-K FOR THE YEAR ENDED DECEMBER 31, 2014

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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 from TCW Global Project Fund II, Ltd.
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
CDC	Commonwealth Development Corporation
CGC	Crump Geothermal Company LLC
CNE	National Energy Commission of Nicaragua
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
EIS	Environmental Impact Statement
ENATREL	Empresa Nicaragüense de Transmision
ENEE	Empresa Nacional de Energía Eléctrica
ENEL	Empresa Nicaragüense de Electricidad
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.

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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
GDL	Geothermal Development Limited
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
INE	Nicaragua Institute of Energy
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
LNG	Liquefied natural gas
Mammoth Pacific	Mammoth-Pacific, L.P.
MACRS	Modified Accelerated Cost Recovery System
MIGA	Multilateral Investment Guaranty 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
NGP	Nevada Geothermal Power
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
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
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.

Term	**Definition**
Orzunil	Orzunil I de Electricidad, Limitada, a wholly owned subsidiary of the Company
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
TASG	Tel Aviv Stock Exchange
TGL	Tikitere Geothermal Power Limited
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 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;

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;

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 nature disasters;

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;

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, including risks arising in connection with our acquisition of our former parent company, Ormat Industries Ltd. (also referred to in this annual report as "Ormat Industries");

competition from other existing 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 resulting from 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;

development and construction of the Solar PV projects, if any, may not materialize as planned;

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. 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 all of our recovered energy-based plants have been constructed by us. We 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 United States 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 current worldwide portfolio of operating geothermal and recovered energy power plants.

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, 2014. 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, 2014 and 2013:

Segment Contribution to Revenues

The following chart sets forth the geographical breakdown of the revenues attributable to our Electricity and Product Segments for each of the years ended December 31, 2014 and 2013:

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 other renewable energy sources, geothermal energy is base load 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 represents 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 recent years, we have expanded our activity to the Solar PV industry. We are monitoring market drivers with potential for developing Solar PV power plants in locations where we can offer competitively priced power generation**.** In early 2014, we completed the work on the Solar PV project, which is located near our Heber complex in

California, and sold the project in March 2014 as a turnkey project.

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 15, 2015. 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 2014 Capacity Factor**	
Geothermal	California	Ormesa complex	100	%	54			
		Heber Complex	100	%	92			
		Mammoth Complex	100	%	29			
		North Brawley	100	%	**18**	(5)		
							78	%
	West Nevada	Steamboat complex	100	%	**73**	(4)		
		Brady Complex	100	%	18			
							86	%
	East Nevada	Tuscarora	100	%	18			
		Jersey Valley	100	%	**10**	(6)		

		McGinness Hills	100	%	**72**	(7)		
		Don A. Campbell	100	%	**19**	(8) (3)		
							93	%
	Hawaii	Puna	100	%	**38**	(3)		
							77	%
	International	Amatitlan	100	%	20			
		Zunil	97	%	**23**	(9) (2)		
		Olkaria III Complex	100	%	110			
							97	%
Total Geothermal					594		86	%
REG		OREG 1	100	%	**22**	(3)		
		OREG 2	100	%	**22**	(3)		
		OREG 3	100	%	**5.5**	(3)		
		OREG 4	100	%	**3.5**	(10)		
Total REG					53		53	%
Total					647			

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(1) We own and operate all of our power plants. Financial institutions hold equity interests in two 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, and (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. In the above table, we show these power plants as being 100% owned because all of the generating capacity is owned by either OPC or ORTP 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" and "ORTP Transaction."

(2) References to generating capacity generally refer to the gross capacity less auxiliary power in the case of all of our existing domestic and foreign power plants, except for 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, the capacity revenues are calculated based on 24 MW capacity unrelated to the actual performance of the reservoir until 2019. 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) In February 2015, we signed a definitive agreement with infrastructure funds managed by Northleaf Capital Partners under which we established a new company, ORPD LLC, that will own Puna Complex, Don A. Campbell, OREG 1, OREG 2, OREG 3 power plants and Northleaf will acquire an approximately 40% equity interest in ORPD LLC. The closing of the transaction, which is subject to customary closing conditions, is expected in the first quarter of 2015. See also in Item 7 - "Management's Discussion and Analysis of Financial Condition and Results of Operations" under the heading "ORPD transaction".

(4) The generating capacity of the Brady and Steamboat complexes was reduced in 2013 due to a decline in the resource temperature in each of these complexes. See "Description of Our Power Plants" below.

(5) Following recent developments, detailed under "Description of Our Power Plants" below, we have decided to operate the North Brawley power plant at a capacity level of approximately 18 MW.

(6) The generating capacity of the Jersey Valley power plant stabilized during 2014.

(7) The McGinness phase 2 power plant reached commercial operation on February 1, 2015 and increased the McGinness complex to 72 MW.

(8) The Don A. Campbell power plant generating capacity is higher than our original expectations of 16MW.

(9) In January 2014, INDE exercised its right under the PPA to become a partner in the Zunil power plant with three percent (3%) equity interest. Detailed information is provided under "Description of Our Power Plants" below.

(10) 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, which is resulting in low power generation.

All of the revenues that we currently derive from the sale of electricity are pursuant to long-term PPAs. In addition, approximately 44.3% of our total revenues in the year ended December 31, 2014 from the sale of electricity by our domestic power plants were derived from 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 85 MW in generating capacity from geothermal power plants in the United States, Kenya and Indonesia that we 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 180 MW.

We have a substantial land position across 32 sites, mostly in the U.S., 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. Generally, we manufacture products only against customer orders and do not manufacture products for our own inventory.

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 power plant 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 the same customers described above that we target for the sale of our power units for recovered energy-based power generation. 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.

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

History

We were formed as a Delaware corporation in 1994 by Ormat Industries, our former parent company. 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 to obtain 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 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 if 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 from oil and gas production. In some oil and gas fields, water is produced as a by-product of the oil and gas extraction. When the 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 through the removal system in order to optimize the performance of the steam turbines. 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 compared with conventional geothermal steam turbine plants. A conventional geothermal steam turbine plant consumes significant quantities of water, causing depletion of the aquifer, and also requires 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.

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Other advantages of our technology include simplicity of operation and easy maintenance. For instance, the OEC employs low RPM and a 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. 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 simple cycle gas turbine, low pressure steam, or medium temperature liquid found in the process industries such as refineries and cement plants. In most cases, we attach an additional heat exchanger in which we circulate thermal oil 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 the OEC 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 exhibit, requires no water treatment (since it is air cooled), 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 69 U.S. patents that are still in force (and have approximately 34 U.S. patents pending). These patents and patents 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. The system-related patents cover not only a particular component 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 pipelines 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 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 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.

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Research and Development

We are conducting research and development activities intended to improve plant performance, reduce costs, and increase the breadth of product offerings. The primary focus of our research and development efforts includes continued improvements to our condensing equipment with improved performance and lower cost and land usage and developing new turbines and specialized remote power units.

We are also continuing with development of new EGS technologies and their application to increase the fluid supply at our existing plants by enhancing the performance of existing wells without additional drilling. We are undertaking this development effort at our Brady Complex in Nevada in cooperation with national laboratories, with funding support from the DOE. Other research and development activity co-funded by the DOE includes testing of new exploration and drilling technologies and practices.

Additionally, we are continuing to evaluate investment opportunities in new companies with technology offering product for renewable energy markets.

Market Opportunity

Domestic

Interest in geothermal energy in the United States remains strong for numerous reasons, including legislative support of renewable portfolio standards, coal and nuclear baseload energy retirement and increasing awareness of the positive value of geothermal characteristics as compared to intermittent renewable technology.

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

In a report issued in April 2014, the GEA identified 124 confirmed and unconfirmed geothermal projects under various phases of consideration or development in 12 U.S. states. The domestic geothermal market experienced modest growth mainly, according to the GEA, due to the uncertainty surrounding federal production tax credit for new projects combined with as lowered demand across the market.

The successful implementation of the various confirmed and unconfirmed geothermal projects identified by the GEA is depended on the respective project sponsor's ability to fully identify the resource, conduct exploration, and carry out development and construction. Accordingly, the GEA's estimates may not be realized, and differences between the actual number of projects completed and those initially estimated 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

An additional factor supporting recent growth in the renewable energy industry is the global concern about the environment. In response to an 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., approximately 40 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 U.S. geothermal power plants in operation 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 the RPS legislation as the most significant driver for us to expand existing power plants and to build new projects.

California

According to information posted on the California Public Utilities Commission website, California's three large investor-owned utilities collectively served 22.27% of their 2013 retail electricity sales with renewable power. These utilities have interim targets each year, with a requirement to attain RPS of 25% by 2016 increasing by two percent every year to 33% by the end of 2020. Publicly-owned utilities in California are also required to procure 33% of retail electricity sales from eligible renewable energy resources by 2020, opening up an additional market of potential off-takers for us even though these utilities do not have interim targets. In addition, a new bill was introduced in California to increase the RPS to 50% by 2030. The bill would require the California Public Utilities Commission to evaluate the cost-effectiveness of renewable energy sources not only in regards to their up-front costs but also for their ability to benefit the grid by supplementing intermittent solar and wind, or by providing base-load electricity generation. The bill, together with the California Governor's call for a clean energy standard that includes 50% of the state's electricity from renewable resource by 2030, could benefit geothermal energy, which has the advantage of generating flexible base-load power, and helping Califormia diversify its mix of renewable resource.

In 2006, California passed a state climate change law, 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 under AB 32. The regulations set a limit on emissions from sources responsible for emitting 80% of California's GHGs. On November 2014, the CARB released the results of its ninth auction (which was the first joint auction for California and Québec allowances) reporting that the vintage 2014 auction clearing price was $12.10 per allowance and the future vintage auction clearing price was $11.86 per allowance. All of the available 2014 and future vintage allowances offered were sold.

In 2014, Assembly Bill No. 2363 (AB-2363), became effective. AB-2363, which requires the California Public Utilities Commission to adopt, by rulemaking, by December 31, 2015, a methodology for determining the costs of integrating eligible renewable energy resources.

Nevada

Nevada's RPS requires NV Energy to supply at least 25% of the total electricity it sells from eligible renewable energy resources by 2025. Nevada's RPS required, for each of 2013 and 2014, that not less than 18% of electricity sold to Nevada retail customers be met with renewable energy resources and credits, and that not less than 5% of that amount be met with solar resources. According to NV Energy's RPS Annual Report, in 2013, Nevada Power exceeded both the 2013 RPS requirement and the 2013 solar RPS requirement, achieving 20.4% and 18.2%, respectively. Sierra exceeded both the 2013 RPS requirement and the 2013 solar RPS requirement, with 34.7% and 16.1% respectively.

In June 2013, the Nevada state legislature passed three bills that were signed into law and expected to support renewable energy development. Senate Bill (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. Senate Bill (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, Assembly Bill (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's RPS require each electric utility that sells electricity for consumption in Hawaii to obtain 15% of its net electricity sales from renewable energy sources by December 31, 2015, 20% by December 31, 2020, and 40% by 2030. According to a 2014 filing made with the Hawaii PUC, in 2013, Hawaiian Electric Company and its subsidiaries exceeded the 2013 RPS requirement, achieving a consolidated RPS of 34.4% of retail electricity sales from eligible renewable energy resources, including electrical energy savings from energy efficiency and solar water hearing technologies. Excluding electrical energy savings from energy efficient and solar water hearing technologies, the 2013 renewable generation percentage for the Hawaiian Electric Companies was 18.2%.

In addition, the Hawaii Electric Light Company submitted a long term energy plan to the HPUC that includes the target goal of generating 92% of its electricity from renewable energy sources by the year 2030.

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 mandatory, market-based carbon dioxide emissions reduction program in the United States. Under RGGI, the participating adopted 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.

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 greenhouse gas 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. 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

At the federal level, in 2011 the EPA’s Tailoring Rule sets thresholds for when permitting requirements under the Clean Air Act’s Prevention of Significant Deterioration and Title V programs apply to certain major sources of GHG emissions. In 2013, President Obama outlined an agenda to help reduce carbon emissions, directing the EPA to complete new pollution standards for both new and existing power plants. The EPA released proposed rules for new fossil fuel fired power plants in September 2013 and for existing fossil fuel-fired power plants in June 2014. In the Clean Power Plan proposal, states identify a path forward using either current or new electricity production and pollution control policies to meet the goals of the proposed program including cutting carbon emission from the power sector by 30% below 2005 levels nationwide by 2030.

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, 2014, 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 a tax credit based on the power produced from a geothermal power plant. These production-based credits, which in 2014 were 2.3 cents per kWh, are 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. For a new solar plant in the U.S. that is placed in service 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. The credit is reduced to 10% for solar projects placed in service after December 31, 2016.

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, 2014, 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. 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 last GEA, there are approximately 12,800 MW of new capacity in early stages of development or under construction in 70 countries and territories around the world (excluding the U.S.). Additionally, developers are actively engaged with and exploring 27 gigawatts (GW) of geothermal resource globally that could potentially develop into power plants over the next decade. The GEA estimates that there are over 674 developing geothermal power projects globally, ranging from prospects to projects in the late stages of development.

The assessment conducted by the GEA is only an estimate that is based on projects and resource reporting by the geothermal industry. Developer ability to fully develop the resource is dependent upon on its capabilities to identify the resource, 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 requirements under the Kyoto Protocol. The Kyoto Protocol was adopted in Kyoto, Japan, in 1997 and entered into force in 2005. In the Bali Action Plan in 2007 and at Copenhagen in 2009 a long-term vision to limit global warming to two degrees Celsius was advanced, and agreed upon in 2010 at the Cancun Conference. The determination to keep within the two degrees Celsius limit led to the creation of the Durban Platform (ADP), in which developed and developing countries will work on a protocol, legal instrument or agreed outcome with legal force, applicable to all parties to the UN Framework Agreement on Climate Change. The new instrument will need to be adopted in 2015 and implemented from 2020. This will be the goal of the 21st U.N. Climate Change Conference that is scheduled to take place in Paris in late 2015.

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:

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.

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 related to tax exemption 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 defined a target to reach at least 80% renewable energy production by 2038.

In **Chile**, where we have three exploration concessions, the Chilean Renewable Energy Act of 2008 required five percent 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 photovoltaic (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. According to the Mexico Country Report 2012, there is a large amount of unexploited geothermal potential in Mexico. This reform affects the electricity market by opening the generation and commercialization of electricity to private companies, the transformation of the Federal Electricity Commission to a for-profit public company, and the redefinition of functions and attributions of the Ministry of Energy. The secondary legislation that establishes the attributions of the public entities, procurement regulation, and normative framework for the productive companies of the State was finalized in 2014.

Many islands nations depend almost entirely on petroleum to supply their electricity demands. With electricity prices average at US$0.35/kWh 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 is believed to be outdated and often unreliable power plants. The larger issue hindering large-scale renewable energy deployments, however, is scale. While 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 Guadeloupe, where a geothermal power plant has been operating since 1985, currently there are no other geothermal operating projects in the Caribbean region. Recently, some deep well drilling exploration was performed in a few islands.

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 the target of increasing 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 development, the government intends to increase the role of renewable energy sources and aims to have them fulfill 25% of the 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. Those regulations included designating approximately 4,000 MW of geothermal projects in its second phase of power acceleration projects to be implemented by 2014, of which the majority are IPP projects and the remaining state utility PLN projects. These targets were not met and the Indonesian government is in the process of issuing new directives for accelerating the geothermal market, including higher ceiling tariffs which may exceed 13.8 c/kWh. For the IPP sector, certain regulations for geothermal projects have been implemented, providing incentives such as investment tax credits and accelerated depreciation, and pricing guidelines to allow preferential power prices for generators; other regulations are being discussed including those that will ease the allocation of forestry permits. On a macro level, the Government of Indonesia committed at the United Nations Climate Change Conference 2009 in Copenhagen to reduce its CO^2 emissions by 26% by 2020.

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 potential.

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 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, 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, pursuant to which the U.S. will invest up to $7.0 billion in sub-Saharan Africa over the next five years with the aim of doubling access to power. The program will partner the U.S. Government with the government of six sub-Saharan countries, among them Kenya, Ethiopia and Tanzania, that have a 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 United States 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 generation. For example, in the U.S., the 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 initially targeted the North American market, where 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. In addition, California modified the Self Generation Incentive Program (SGIP), which allows recovered energy-based generation to qualify for a per watt incentive. North Dakota, South Dakota, and the U.S. Department of Agriculture (through the Rural Utilities Service) have approved recovered energy-based power generation units as renewable energy resources, which qualifies recovered energy-based power generators for federally funded, low interest loans, as a priority for our efforts in this regards.

Recovery of waste heat is also considered “environmentally friendly” in the western Canadian provinces. We believe that Europe and other markets worldwide may offer similar opportunities in recovered energy-based power generation.

In 2012, the Governor of Utah signed into law Senate Bill 12 (SB12) that enables the sale of electricity directly to large energy users. The direct purchasing, while still in early implementation, could create a market opportunity for our REG units in Utah.

In addition, in Colorado the state PUC ruled that Xcel Energy, the largest utility in Colorado, will begin offering a $500/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 processes into electricity.

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

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.

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 serve 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, creating a significant competitive advantage 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.

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.

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 69 U.S. patents in force (and have approximately 34 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 leading manufacturer and provider of products and services related to renewable energy. 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 operation into global markets* – increasing our business development activities in an effort to grow our business in the global markets in both business segments;

- *Acquisition of New Assets* — acquiring from third parties additional geothermal and other renewable assets;

- *Manufacturing and Providing Products and 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;

- *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;

- *Development and Construction of Recovered Energy Power Plants* — since we utilize the same infrastructure to develop, supply or operate Geothermal and REG projects, we can capitalize on opportunities in the REG markets and continue to add successful projects to both our electricity and product segments in this sector; and

- *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 12, 2015, we announced the completion of the share exchange, which is the first and primary step of a series of transactions contemplated by the Share Exchange Agreement and Plan of Merger (the "Share Exchange Agreement"), dated as of November 10, 2014, by and among us, Ormat Industries, our then-parent company, and Ormat Systems. 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 total shares outstanding, which we believe would help elevate trading volume and may increase equity coverage.

Pursuant to the Share Exchange Agreement, we agreed to acquire Ormat Industries through a share exchange in which we issued 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. Following the satisfaction of the various conditions precedent to closing of the share exchange, including (i) the receipt of approval from the District Court of Tel Aviv – Jaffa of the scheme of arrangement under Israeli law represented by the share exchange; (ii) the approval by the controlling shareholder of the issuance of our shares of common stock to the shareholders of Ormat Industries in connection with the share exchange; (iii) the approval of the Share Exchange Agreement by the shareholders of Ormat Industries; and (iv) the maintenance in full force and effect of a ruling that has been obtained from the Israel Tax Authority confirming the Israeli income tax treatment of the transactions contemplated by the Share Exchange Agreement (the "Israeli Tax Ruling"); the share exchange was completed on February 12, 2015.

As previously disclosed, we entered into several agreements in connection with the Share Exchange Agreement, including the following:

o 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, following the share exchange, beneficially own approximately 15.06% and 8.84% 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.

o 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:

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;

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;

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

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.

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

o 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, we announced that our wholly-owned subsidiary has entered into a binding agreement with infrastructure funds managed by Northleaf Capital Partners (Northleaf) under which Ormat will contribute certain geothermal and recovered energy generation power plants into a newly established holding company subsidiary, ORPD LLC (ORPD), and Northleaf will acquire an approximately 40% equity interest in the ORPD. We will raise approximately $175 million from the transaction. The transaction is expected to close in March 2015, subject to customary closing conditions.

The power plants that will be contributed to ORPD as part of the transaction include our 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. We will continue to consolidate the ORPD and its assets, and will continue to provide day-to-day management control, operations and maintenance control over the projects.

On February 5, 2015, 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, may 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 our McGinness Hills geothermal power plant located in Lander County, Nevada has begun commercial operation. Since February 1, 2015, the complex sells electricity under the amended PPA with NV Energy at a new energy rate of $85.58/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 McGinness Hills Phase 2 plant that came on line on February 1, 2015, brought the complex's total capacity to approximately 72MW. We have a contract with NV Energy to sell energy produced at McGinness Hills through December 2032.

On December 4, 2014, we announced the signing of an amended and restated PPA with KPLC, paving the way for the expansion of the Olkaria complex. Under the terms of the PPA, we expect to increase the generating capacity of the complex by 24 MW, bringing the complex's total capacity to 134 MW. The fourth plant is expected to come on line in the second half of 2016 and to sell electricity under a 20 year PPA with KPLC.

On November 3, 2014, we, through a majority owned subsidiary (the Project Company), signed a 25-year PPA with KPLC and a project implementation and steam supply agreement (PISSA) with Geothermal Development Company (GDC) for the 35MW Menengai geothermal project in Kenya. Under the PISSA agreement, the Project Company will finance, design, construct, install, operate and maintain the 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.

On November 3, 2014, we, through a wholly owned subsidiary, signed a $22.3 million engineering, procurement and construction (EPC) agreement with the Utah Associated Municipal Power System (UAMPS). We will install an air-cooled Ormat Energy Converter (OEC) at the Kern River Transmission Company's Veyo natural gas compressor station in Southern Utah. This new recovered energy generation (REG) project will generate power using heat that would otherwise have not have been utilized.

On September 30, 2014, we repaid in full the outstanding amount of approximately $30.0 million from our $42.0 million loan with EIG Global Project Fund II, Ltd. (formerly TCW). The $42.0 million loan was signed in 2009 to refinance Ormat's investment in the 20 MW Amatitlan geothermal power plant located in Guatemala. The loan was scheduled to mature on June 15, 2016 and bears interest at a rate of 9.83%. This repayment resulted in a one-time charge to interest expense of approximately $1.1 million. We are currently negotiating a new financing agreement that we believe will contain improved terms.

On August 29, 2014, we announced the signing of a $140.0 million loan under the OFC 2 senior secured notes to finance the construction of the McGinness Hills Phase 2 plant in Nevada. This drawdown is the last tranche under the Note Purchase Agreement with John Hancock Life Insurance Company (USA) and guaranteed by the U.S. Department of Energy’s Loan Programs Office in accordance with and subject to the Department’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 Notes, which include loans for the Tuscarora, Jersey Valley and McGinness Hills complexes, are rated “BBB” by Standard & Poor’s.

On August 5, 2014, we signed a definitive Purchase and Sale Agreement with Alternative Earth Resources Inc. (AER), pursuant to which we paid $1.5 million in cash in consideration for (i) AER's 50% interest in Crump Geyser and North Valley geothermal project assets and (ii) an option, exercisable over a four-year period, to purchase certain of AER's New Truckhaven geothermal asset.

On July 1, 2014, Mr. Isaac Angel assumed the position of CEO of our company. He succeeded Mrs. Yehudit (Dita) Bronicki, who announced her retirement in November 2013. Mrs. Bronicki continues to serve as director of Ormat in a non-executive capacity. In addition, effective June 30, 2014, Mr. Gillon Beck stepped down from his position of Chairman of the Board of Directors of the Company and Mr. Yoram Bronicki assumed the position of Chairman. Mr. Beck continues to serve as a director of the Company. Upon assuming the position of the Chairman of the Board, Mr. Yoram Bronicki relinquished his position as President and Chief Operating Officer of the Company.

On May 23, 2014, we announced the closing of the $1.17 billion financing agreements entered into by the Sarulla consortium for the 330-megawatt (MW) project in North Sumatra in Indonesia. The Japan Bank for International Cooperation (JBIC), the Asian Development Bank and six commercial banks provided the Sarulla project construction and term loans under a limited recourse financing package backed by political risk guarantees from JBIC. The consortium expects the first phase of operations to commence in 2016. The remaining two phases of operations are scheduled to commence within 18 months thereafter. We will supply our Ormat Energy Converters to the power plants and we added the $254.0 million supply contract to our Product Segment backlog. According to the current project plan, we started to recognize revenue from the project during the third quarter of 2014 and will continue to recognize revenues over the course of the next three to four years.

On March 26, 2014, we signed an agreement with RET Holdings, LLC to sell the Heber Solar project in Imperial County, California for $35.25 million. We received the first payment of $15.0 million in the first quarter of 2014 and the second payment for the remaining $20.25 million in the second quarter of 2014. We recognized pre-tax gain of $7.6 million in the second quarter of 2014.

On February 4, 2014, we announced that we successfully completed construction and reached commercial operation of Plant 3 in the Olkaria III geothermal power plant complex in Kenya. With Plant 3 online, the complex's total generation capacity has increased to 110 MW. The power generated by the Olkaria III complex is sold under a 20-year PPA with KPLC. On November 25, 2013, we announced that we drew down the remaining $45.0 million comprising Tranche III of the previously announced $310.0 million project finance facility with OPIC.

On January 23, 2014, we announced that we successfully completed the scope of work needed to bring the Mammoth G1 geothermal power plant in Mono County, California to full capacity. The 6 MW plant reached commercial operation under the new PPA with Pacific, Gas and Electric (PG&E) that allows for hourly energy deliveries of up to 7.5 MW and, as of December 26, 2013, it received the full commercial rate defined in the PPA.

On January 22, 2014, we announced that one of our wholly owned subsidiaries signed an amendment to the PPA with INDE for the Zunil geothermal power plant in Guatemala, which extends the term of the PPA from 2019 to 2034. The 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 a tariff increase. Additionally, INDE exercised its right under the PPA to become a partner in the Zunil power plant and to acquire a three percent equity interest therein.

On January 6, 2014, we announced that we completed the construction of the 16 MW Don A. Campbell geothermal power plant in Mineral County, Nevada. The Don A. Campbell facility, formerly Wild Rose, receives a full rate of $99.0 per MWh with no annual escalation under the terms of the PPA, signed in April 2013, with Southern California Public Power Authority (SCPPA). SCPPA resells the power from the Don A. Campbell geothermal power plant to the Los Angeles Department of Water and Power (LADWP) and Burbank Water and Power through NV Energy Inc.'s transmission system.

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. Acquisition of 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 United States 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 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 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 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 to maintain the geothermal resource and surface conditions. We generally drill the production wells ourselves although in some cases we use outside contractors.

The cost for each production 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 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 the year ended December 31, 2014, in the Electricity Segment we focused on the completion of the Olkaria III plant 3 and the construction of the McGinness Hills phase 2 power plant and began construction in the Don A. Campbell phase 2. We began construction in the Olkaria III plant 3 and McGinness Hills phase 2 during the year ended December 31, 2013, and the Olkaria III Plant 2 during the year ended December 31, 2012.

During the year ended December 31, 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 the year ended December 31, 2013, we discontinued exploration and development activities at three sites, including Magic Reservoir in Idaho, Wildhorse (Mustang) in Nevada and Drum Mountain in Utah. During the year ended December 31, 2012, we discontinued exploration and development activities at five sites, including Leach Hot springs, Hyder Hot Springs, Seven Devil, Smith Creek and Walker River in Nevada.

After conducting exploratory studies and drilling in those sites, we concluded that the geothermal resource would not support commercial operations at that time. Costs associated with exploration activities at these sites were expensed accordingly (see “Write-off of Unsuccessful Exploration Activities” under Item 7 — “Management Discussion and Analysis of Financial Condition and Results of Operations”).

We added to our exploration activities four, two and five sites during the years ended December 31, 2014, 2013 and 2012, 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 United States, 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 called PPAs) for the sale of electricity or the conversion of geothermal resources into electricity. Although a power plant's revenues under a PPA previously 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 combination of non-recourse or limited recourse debt, including lease financing, internally generated cash, which includes funds from operation, as well as proceeds from loans under corporate credit facilities, sale of securities, and other sources of liquidity. 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 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. To the extent of these limited recourse obligations, creditors of a project financing of a particular power plant may have direct recourse to us.

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 one of our power plants.

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 contracts 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 revenue loss 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 all of our foreign power plants in operation.

Description of Our Leases and Lands

We have domestic leases on approximately 374,176 acres of federal, state, and private land in Alaska, California, Hawaii, Idaho, Nevada, New Mexico, Oregon and Utah. The approximate breakdown between federal, state, private leases and owned land is as follows:

- 72% are leases with the U.S. government, acting through the BLM;
- 15% are leases with private landowners and/or leaseholders;
- 11% are leases with various states, none of which is currently material; and
- 2% 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 174,000 acres, most of which are geothermal exploration licenses in three prospects 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 have been 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. We have waived three of the six concessions we held. As of the date of this annual report we have the exclusive right to apply for an exploitation license for the remaining three sites. Our exclusive rights will expire on March 7, 2016, and obtaining such license is subject to an 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	18MW

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 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 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 273 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	Approximately four degrees Fahrenheit per year was historically observed at Brady, and two degrees Fahrenheit was observed in 2013. The temperature decline at Desert Peak is approximately two degrees Fahrenheit per year. At Desert Peak, two formally idle wells were connected for injection and two former injection were shut in to reduce the rate of cooling.
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 Brady, and OPC Transaction in the case of Desert Peak 2.

Don A. Campbell Project

Location	Mineral County, Nevada
Generating Capacity	19 MW
Number of Power Plants	One
Technology	The Don A. Campbell power plant utilizes an air cooled binary system.

Subsurface Improvements	Five production wells and three injection wells are connected to the plant.
Material Equipment	One air cooled OEC unit with the Balance of Plant equipment.
Age	The power plant is in its second year of operation.
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 to 1,900 feet) and three injection wells (from depths of 649 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	From the beginning of operation the 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 in leases from BLM.
Power Purchaser	SCPPA
PPA Expiration Date	2034
Financing	Corporate funds and cash grant that we received from the U.S. Treasury.
Supplemental Information	In February 2015, we signed a definitive agreement with Northleaf under which we established a new company, ORPD LLC, that will own Puna Complex, Don A. Campbell, OREG 1, OREG 2, OREG 3 power plants and Northleaf will acquire an approximately 40% equity interest in ORPD LLC. The agreements will be in effect at closing expected in the first quarter of 2015, subject to customary closing conditions. Discussed in Item 7 - "Management's Discussion and Analysis of Financial Condition and Results of Operations" under the heading "ORPD transaction".

Heber Complex

Location	Heber, Imperial County, California
Generating Capacity	92 MW (See supplemental information below).
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	31 production wells and 34 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 347 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	Two PPAs with Southern California Edison and one PPA with SCPPA.
PPA Expiration Date	Heber 1 — 2015, Heber 2 — 2023, and Heber South — 2031. The output from the Gould 1 and Gould 2 power plants is sold under the PPAs of 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 will replace the current Heber 1 PPA with Southern California Edison upon the expiration of the current PPA expected at the end of 2015. In 2012, we drilled a new well as an upgrade project for the Heber 1 area to make better use of the available resource. We drilled two additional wells in 2013 and four old wells were decommissioned. In 2015, we intend to drill one more well and perform upgrades to surface equipment. At the end of this process, we expect the capacity of the complex to reach 92MW.

Jersey Valley Power Plant

Location	Pershing County, Nevada
Generating Capacity	10 MW (see supplemental information below).
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 320 degrees Fahrenheit.
Resource Cooling	The rate of cooling was six degree Fahrenheit in 2014.
Power Purchaser	Nevada Power Company
PPA Expiration Date	2032
Financing	Corporate funds and ITC cash grant from the U.S. Treasury.
	Once the Jersey Valley power plant reaches certain operational targets and meets other conditions precedent, we have the ability to borrow additional funds under the OFC 2 Senior Secured Notes.
Supplemental Information	In 2014, we increased the injection capacity of the Jersey Valley power plant, which has been limiting generation in its early years. Following the work we believe the power plant can operate at a stable capacity of 10MW.

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 G-2 and G-3 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.

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	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 two 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 - PG&E and G2 -Southern California Edison.
PPA Expiration Date	G-1 and G-3 — 2034, G-2 and— 2027.
Financing	OFC Senior Secured Notes and ORTP Transaction.
Supplemental Information	In 2012, we entered into two new PPAs with PG&E, which replaced the current G-1 (December 2013) and G-3 PPAs (April 2013) with Southern California Edison.
	In January 2014, we announced that we completed the scope of work needed to bring the G1 geothermal power plant to full capacity. The plant reached commercial operation under the new PPA with PG&E and now receives the full commercial rate defined in the PPA.

McGinness Hills Complex

Location	Lander County, Nevada
Generating Capacity	72 MW
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 are currently held by the payment of 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 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, 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 337 degrees Fahrenheit and the fluids are sourced from the reservoir at elevations between 2,000 to 5,000 feet below the surface.

	The average temperature of the resource is approximately 335 degrees Fahrenheit.
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.

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 335 degrees Fahrenheit.
Resource Cooling	We have not observed a noticeable cooling.

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. We plan to continue to sell the generated power from the North Brawley plant to Southern California Edison under the existing PPA at a capacity level of approximately 18 MW. We intend to refrain from additional capital investment to expand the capacity and reduce the operational costs of the North Brawley power plant until further geological analysis is completed and/or a higher energy rate will be secured. During the fourth quarter of 2012, we recognized an impairment charge of $229.1 million for this plant.

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 February 2015, we signed a definitive agreement with Northleaf under which we established a new company, ORPD LLC, that will own Puna Complex, Don A. Campbell, OREG 1, OREG 2, OREG 3 power plants and Northleaf will acquire an approximately 40% equity interest in ORPD LLC. The agreements will be in effect at closing expected in the first quarter of 2015, subject to customary closing conditions. Discussed in 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 February 2015, we signed a definitive agreement with Northleaf under which we established a new company, ORPD LLC, that will own Puna Complex, Don A. Campbell, OREG 1, OREG 2, OREG 3 power plants and Northleaf will acquire an approximately 40% equity interest in ORPD LLC. The agreements will be in effect at closing expected in the first quarter of 2015, subject to customary closing conditions. Discussed in 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 February 2015, we signed a definitive agreement with Northleaf under which we established a new company, ORPD LLC, that will own Puna Complex, Don A. Campbell, OREG 1, OREG 2, OREG 3 power plants and Northleaf will acquire an approximately 40% equity interest in ORPD LLC. The agreements will be in effect at closing expected in the first quarter of 2015, subject to customary closing conditions. Discussed in 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.
Supplemental Information	The OREG 4 power plant was tested for impairment in the third quarter of 2012 due to continued low run time of the compressor station that serves as its heat source, which resulted in low power generation and revenue. As a result, during the third quarter of 2012 we recognized an impairment charge of $7.3 million for this plant.

Ormesa Complex

Location	East Mesa, Imperial County, California
Generating Capacity	54 MW
Number of Power Plants	Four (OG I, OG II, GEM 2 and GEM 3)
Technology	The OG plants utilize a binary system and the GEM plants utilize a flash system. The complex uses a water cooling system.
Subsurface Improvements	31 production wells and 53 injection wells connected to the plants through a gathering system.
Material Major Equipment	32 OEC units and two steam turbines with the Balance of Plant equipment.
Age	

The various OG I units 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 plants 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 304 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.
Sources of Makeup Water	Water is provided by the IID.
Power Purchaser	Southern California Edison under a single PPA.
PPA Expiration Date	2018
Financing	OFC Senior Secured Notes and ORTP Transaction.

<u>Puna Complex</u>

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	Five production wells and four 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 area 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.
Supplemental Information	Following the Hurricane Iselle that hit the Big Island of Hawaii in August 2014, we were required to temporarily shut down our Puna power plant. As a result, one of the production wells did not fully recover and the plant lost approximately 5MW. We started the drilling of a sixth production well and the conversion of one of the drilled wells into an injection well.

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.

We signed a definitive agreement with Northleaf under which we established a new company, ORPD LLC, that owns Puna Complex, Don A. Campbell, OREG 1, OREG 2, OREG 3 power plants and Northleaf will acquire an approximately 40% equity interest in ORPD LLC. The agreements will be in effect at closing expected in the first quarter of 2015, subject to customary closing conditions. Discussed in Item 7 - “Management’s Discussion and Analysis of Financial Condition and Results of Operations” under the heading “ORPD transaction”.

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 nine injection wells connected to the plants through a gathering system. We intend to tie into the plant in 2015 one new production well and one new injection well that were drilled in 2014.
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 285 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).
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 a new injection well was drilled in 2014 in the new land which we expect will reduce the complex cooling. We are planning to further optimize the field in 2015 to reduce the cooling and maximize power output.

<u>Tuscarora Power Plant</u>

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 339 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.

Foreign Operating Power Plants

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

Amatitlan Power Plant (Guatemala)

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 and two percent of revenues exceeding 20.5 MW.
	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 524 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 project loan from TCW Global Project Fund II, Ltd., which we repaid in full in September 2014. Currently, we are looking to finance the project with financial institution.

Olkaria III Complex (Kenya)

Location	Naivasha, Kenya
Generating Capacity	110 MW
Number of Power Plants	Four (Olkaria III Phase 1 and Olkaria III Phase 2, together Plant 1, Plant 2 and Plant 3).
Technology	The Olkaria III complex utilizes an air cooled binary system.

Subsurface Improvements	16 production wells and four injection wells connected to the plants through a gathering system.
Major Equipment	11 OEC units together with the Balance of Plant equipment.
Age	Plant 3 commenced commercial operation in January 2014 and plant 2 in April 2013. The first phase of Plant 1commenced 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	2033
Financing	Senior secured project finance loan from OPIC and a subordinated loan from DEG.
Supplemental Information	We recently signed an amended and restated PPA with KPLC, Under the terms of the PPA, we expect to increase the generating capacity of the complex by 24 MW, bringing the complex’s total capacity to 134 MW. The fourth plant is expected to come on line in the second half of 2016 and to sell electricity under a 20 years PPA with KPLC

Zunil Power Plant (Guatemala)

Location	Zunil, Guatemala
Generating Capacity	24 MW
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.
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. Currently, the power plant generates approximately 9.5 MW due to lack of sufficient geothermal resource supply. We plan to improve the heat supply to gradually increase generation, subject to monitoring and assessment of the geothermal reservoir. We

expect that this improvement and the increase in tariff will increase the energy portion of revenues. We plan to drill a new production well in 2015 that we expect will increase output by 5 MW to 10 MW.

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

We are in varying stages of construction of projects, some of them we fully released and are in different stages of construction and two projects are each in an initial stage of construction.

The following is a description of projects in Nevada, Kenya and Indonesia with an expected total generating capacity of approximately 86 MW that were released and are in different stages of construction.

Don. A. Campbell Phase 2 (U.S.)

Location	Mineral County, Nevada
Projected Generating Capacity	19 MW
Projected Technology	Phase 2 power plant will utilize a binary system.
Condition	Field development and construction have begun
Land and Mineral Rights	The Don A. Campbell area is comprised of BLM leases. Since we declared commercial operation of Don A. Campbell phase 1, 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 to 1,900 feet) and three injection wells (from depths of 649 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.
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	The PPA for this power plant is in approval process of the off-taker
Financing	Corporate funds
Projected Operation	First quarter-2016
Supplemental Information	In February 2015, we signed a definitive agreement with Northleaf under which we established a new company, ORPD LLC, that will own Puna Complex, Don A. Campbell, OREG 1, OREG 2, and OREG 3 power plants and Northleaf will acquire an approximately 40% equity interest in ORPD LLC. Once Don A. Campbell phase 2 is completed and tested it will be added to ORPD LLC at a price agreed upon with Northleaf. The agreements will be in effect at closing expected in the first quarter of 2015, subject to customary closing conditions. The agreements are discussed in Item 7 - “Management’s Discussion and Analysis of Financial Condition and Results of Operations” under the heading “ORPD transaction”.

Olkaria III – Plant 4 (Kenya)

Location	Naivasha, Kenya
Projected Generating Capacity	24MW
Projected Technology	Plant 4 will utilize an air cooled binary system.
Condition	Field development of Plant 4 is in its final stage and site construction has started
Subsurface Improvement	Two new production wells are planned to be drilled.
Land and Mineral Rights	The total Olkaria III area is comprised of government leases. See description above under “Olkaria III Complex”.
Resource Information	The Olkaria III geothermal field is on the west side of the greater Olkaria geothermal area located within the Rift Valley at approximately 6,890 feet above sea level.
	Hot geothermal fluids rise up from deep in the northeastern portion of the concession area through low permeability at a shallow depth to a high productivity two-phase region from 3,280 to 4,270 feet above sea level.
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	20 years from COD of Plant 4.
Financing	Corporate finance
Projected Operation	Second half of 2016
Supplemental Information	We amended and restated the existing PPA with KPLC. The amended and restated PPA provides for the construction of a new 24 MW power plant bringing the complex's total capacity to 134 MW. Two new production wells are planned to be drilled.

Sarulla (Indonesia)

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,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	Field development is ongoing. Engineering, procurement and Construction are in progress. Infrastructure work has completed.
Land and Mineral Rights	All land for the project was acquired.
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 drilling 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:

<u>Carson Lake Project (U.S.)</u>

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; currently on hold.
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.

	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; however, we are still experiencing delays in the permitting process for the transmission line.

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 United States, Kenya, and Honduras. 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 58 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 2015.

e-Bay REG Project (U.S.)

In September 2013, we entered a Joint Development Agreement with eBay Inc. 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.

Platanares Project (Honduras)

In December 2013, we completed the asset acquisition of the Geotérmica Platanares geothermal project in Honduras from ELCOSA, a privately owned Honduran energy company, upon satisfaction of the required conditions precedent. We will hold the assets, including the project’s wells, land, permits and a PPA for up to 35 MW with ENEE, the national utility of Honduras, under a BOT structure for 15 years from commercial operation of the first phase. Under certain circumstances the agreement can be extended by up to one year.

Platanares is a late-stage development geothermal project whose previous owners conducted exploration work. Once the well field is appraised, we will determine the expected capacity and begin construction on the first phase anticipated to be approximately 18 MW and to reach commercial operation in 2017.

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 Kenya Power and Lightning Co. Ltd. (KPLC) and a project implementation and steam supply agreement (PISSA) with Geothermal Development Company (GDC) for the 35MW Menengai geothermal project in Kenya.

Under the PISSA agreement, the Project Company will finance, design, construct, install, operate and maintain the 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.

Exploration 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. Our land position is comprised of various leases and private land for geothermal resources of approximately 284,678 acres in 27 prospects including the following:

Nevada [12]

1.	Aqua Quieta	Completed exploration studies;
2.	Argenta	Under exploration studies;
3.	Baltazar	Completed exploration studies;
4.	Beowawe	Under exploration studies;
5.	Dixie Hope	Under exploratory drilling
6.	Edwards Creek	Under exploratory drilling;
7.	Hycroft	Under exploration studies;
8.	North Valley	Under exploration studies;
9.	South Jersey	Lease acquired but no further action has yet been taken;
10.	Trinity	Under exploration studies;
11.	Tungsten Mountain	Under exploratory drilling; and
12.	Tuscarora	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 [3]

1. Kona	Under exploration studies.
2. Kula	Lease acquired but no further action has yet been taken; and
3. Ulupalakua (Maui)	Completed exploration studies.

Oregon [3]

1. Glass Buttes — Midnight Point	Started exploratory drilling;
2. Newberry — Twilight	Started exploratory drilling; and
3. Lakeview/ Goose Lake	Completed exploration studies.

Utah [1]

1. Whirlwind Valley Under 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

In addition, we have exploration concessions for geothermal resources of approximately 144,000 acres in the following prospects:

Chile [3]

1. Mariman Under exploration studies;
2. Quinohuen Under exploration studies; and
3. Sollipulli Under exploration studies.

We also have an option to enter into geothermal leases covering more than 44,000 acres under a lease option agreement with Weyerhaeuser Company and agreement to conduct exploration activity at Warm Springs Tribe. We are currently exploring the following prospects:

Oregon [2]

1.	Winema	Started exploration studies; and
2.	Warm Springs Tribe	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 consideration for the power units is usually paid 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.

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 a capacity ranging between 200 watts and 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 for various other uses, including heavy duty direct current generators. The terms of sale of the turbo-generators are similar to those for the power units produced 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 the same customers described above that we target for the sale of our power units for recovered energy-based power generation. Unlike many other companies that provide EPC services, we have an advantage in that we are using our own manufactured equipment and thus have better control over the timing and delivery of required equipment and its 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 and remote power units and other generators, we enter, from time to time, into sales agreements 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 $325.8 million as of February 26, 2015, which includes revenues for the period between January 1, 2015 and February 19, 2015, compared to $165.0 million as of February 26, 2014, which included revenues for the period between January 1, 2014 and February 15, 2014.

The following is a breakdown of the Product Segment backlog as of February 26, 2015 (dollars in millions):

	Expected Completion of the Contract	**Sales Expected to be Recognized in 2015**	**Sales Expected to be Recognized in the years following 2015**	**Expected Until End of Contract**
Geothermal	2017	148.7 - 156.9	130.9 - 139.1	$ 282.8
Recovered Energy	2016	18.2 - 19.3	3.2 - 4.3	22.5
Remote Power Units	2016	7.4 - 7.8	2.3 - 2.7	10.1
Other	2017	5.7 - 6.0	4.4 - 4.7	10.4
Total		**180.0 - 190.0**	**140.8 - 150.8**	**325.8**

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.

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 United States are CalEnergy, Calpine Corporation, Terra-Gen Power LLC, Enel Green Power S.p.A and other smaller-sized pure play developers. Outside the United States, in many cases our competitors are companies that gained experience developing geothermal projects in their own countries and are now seeking to take this experience and develop geothermal projects in other countries. The main ones are Chevron Corporation, Energy Development Corporation (EDC) from the Philippines, Mighty River Power (MRP) and Contact Energy Limited from New Zealand, Origin Energy from Australia, 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. The 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.

The low enthalpy competitors are either 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 in excess of 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.

When the proposed project is an EPC project 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, 2014 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 13.5%, 16.5%, 8.0% and 3.9% of revenues, respectively, for the year ended December 31, 2014. Based on publicly available information, as of December 31, 2014, the issuer ratings of Southern California Edison, HELCO, Sierra Pacific Power Company, Nevada Power Company, and SCPPA 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)	Baa1(stable outlook)
Sierra Pacific Power Company	BBB+ (stable outlook)	Baa1 (stable outlook)
Nevada Power Company	BBB+ (stable outlook)	Baa1 (stable outlook)
SCPPA	A- (Negative outlook)	Aa3 (stable outlook)
Pacific, Gas and Electric	BBB (Negative 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 such raw materials are readily available from various suppliers.

We use subcontractors for some of the manufacturing for 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, 2014, we employed 1,095 employees, of which 471 were located in the United States, 515 were located in Israel and 109 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.

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 United States, 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 in 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 is currently under litigation in the federal Court of Appeals for the Ninth Circuit in California.

We have no collective bargaining agreements with respect to our Israeli employees. However, by order of the Israeli Ministry of Industry, Trade and Labor, 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 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 all of our foreign power plants in operation, 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 the 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 United States 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 the 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 United States 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, the 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, the 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 received 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 and 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 United States, 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, 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 68.3% of our total revenues for the year ended December 31, 2014 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, 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 2013 we replaced old equipment at the Mammoth complex, which were not manufactured by us. 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. In our North Brawley power plant in 2014 we also experienced an uncontrolled flow in one of the production wells that caused to a reduction in generation and increased costs. 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 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 PPAs, receipt of required governmental permits, obtaining adequate financing, and the timely implementation and satisfactory completion of construction. 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 United States, Kenya, Chile, Guatemala, New Zealand, Honduras and Indonesia, 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:

- unanticipated cost increases;
- shortages and inconsistent qualities of equipment, material and labor;
- work stoppages;
- inability to obtain permits and other regulatory matters;
- failure by key contractors and vendors to timely and properly perform, including where we will use equipment manufactured by others;
- failure by key suppliers to provide steam for electricity generation including in the Menengai project in Kenya where the steam will be provided by others.
- inability to secure the required transmission capacity;
- adverse environmental and geological conditions (including inclement weather conditions); 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 prospects.

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

We have entered into an agreement to sell 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 United States, 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 United States, 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, recent sentiment suggests increased opposition to the presence of foreign investors generally, including in the electricity sector. 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 revenue 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 revenue 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.

Under the PPAs of our Burdette (Galena 1), Desert Peak 2, Galena 2, Galena 3, Jersey Valley, McGinness Hills, Tuscarora North Brawley and Don A. Campbell power plants, we may be required to make payments to the relevant power purchaser in an amount equal to such purchaser’s replacement costs for renewable energy relating to any shortfall amount of renewable energy that we do not provide as required under the PPA and which such power purchaser is forced to obtain from an alternate source. Also, under the PPAs of our Zunil and Puna power plants, we may be required to pay penalties payments to the relevant power purchaser in an amount agreed upon if we have shortfall amounts of energy that we do not provide as required under the PPA. All of these plants were in commercial operation in 2014, and to date, the shortfall amount has not been material. In addition, we may be required to make payments to the relevant power purchaser in an amount equal to its replacement costs relating to any renewable energy credits we do not provide as required under the relevant PPA. We may be subject to certain penalties, and we may also be required to pay liquidated damages if certain minimum performance requirements are not met under certain of our PPAs. With respect to the Brady PPA, we may also be required to pay liquidated damages of approximately $1.5 million (increased by the percent change in GNP deflator) to our power purchaser if the relevant power plant does not maintain availability of at least 85% during applicable peak periods. Any or all of these 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 electrical energy itself or purchased such energy 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 and going forward it will be based on Southern California Edison's SRAC, as determined by the CPUC. These 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.

In December 2010, a global settlement (Global Settlement) relating primarily to the purchase and payment obligations of investor-owned utilities to Qualifying Facilities was approved by the CPUC and became effective on November 23, 2011. Under the terms of the Global Settlement, existing Qualifying Facilities with "Legacy PPAs" (meaning any PPA that was in effect at the time the Global Settlement went into effect) had the option to choose to enter into a "Legacy PPA Amendment" within 180 days of the effectiveness of the Global Settlement. The Legacy PPA Amendment allowed a Qualifying Facility to choose a pricing methodology option going forward from the "pricing effective date", which in our case was the end of the fixed rate period that terminated April 2012 under a prior settlement agreement with Southern California Edison until December 31, 2014, after which the SRAC will be tied only to a formula with energy market heat rates. The pricing options that we chose for our PPAs were as follows:

In the case of our Ormesa complex and Heber complex PPAs we switched to a new SRAC methodology, which includes fixed rates, declining heat rates, a variable O&M component, an adjustment based on location, and a price adjustment if GHG costs are imposed on the facility, all until December 31, 2014, after which the SRAC will be tied only to a formula with energy market heat rates; and

In the case of our Mammoth G2 power plant PPA we switched to the same formula specified in (1) above but with somewhat higher heat rates, no GHG cost adder and no location adjustment (for renewable resources).

The Global Settlement further provides that after July 1, 2015 if the term of a Qualifying Facility's Legacy PPA expires, the investor-owned utilities would have no obligation to purchase power from the Qualifying Facility if the Qualifying Facility has a generating capacity in excess of 20 MW. Qualifying Facilities below 20 MW 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. Our existing PPAs with California investor-owned utilities are not affected by this waiver.

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.

Our financial performance is significantly dependent on the successful operation of our power plants, which is subject to 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 United States, 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 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.

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, 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.

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 revenue loss. 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 or construct and operate Solar PV facilities which require large areas of relatively flat land.

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, thereby affecting our ability to utilize, access, inject, and/or transport geothermal resources on or underneath the affected surface areas. 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, 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, and on the supply of various industrial equipment components that we use. We currently obtain all such materials 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 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 all of our 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 and all of our 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 recent political instability and civil unrest in the Middle East and North Africa (including the ongoing civil war in Syria) as well as the recently 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 United States 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 26, 2015, Bronicki and FIMI beneficially own, collectively, approximately 23.9% 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 15.1% of our outstanding common stock, Bronicki holds approximately 8.8% 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. As more fully described above under " – Recent Developments", in connection with the Share Exchange Agreement, we entered with FIMI and Bronicki into several agreements, 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 feet 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 2014, other than as described below.

Jon Olson and Hilary Wilt, together with Puna Pono Alliance, an unincorporated association, filed suit on February 17, 2015, in the Third Circuit Court for the State of Hawaii, seeking declaratory and injunctive relief against Puna Geothermal Venture and the County of Hawaii. The relief requested includes a declaratory ruling that a County ordinance adopted in 2012, prohibiting night time geothermal drilling and drilling operations, applies to PGV’s current drilling activities at the KS-16 well. We believe that the allegations of the complaint have no merit, and will defend itself vigorously.

On July 8, 2014, Global Community Monitor, LiUNA, and two residents of Bishop, California filed a complaint in the United States District Court for the Eastern District of California, alleging that Mammoth Pacific, L.P., Ormat Technologies, Inc. and Ormat Nevada, Inc. 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 ("CAA") and Great Basin Unified Air Pollution Control District ("District") rules. The Company believes the complaint is without merit, and intends to vigorously defend itself against the allegations set forth in the complaint and to take all necessary legal action to have the complaint dismissed. Filing of the complaint in and of itself does not have any immediate adverse implications for the Mammoth plants.

On April 5, 2012, the International Brotherhood of Electrical Workers Local 1260 ("Union") filed a petition with the National Labor Relations Board ("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 Employer's obligation to negotiate with the Union were appealed to the United States Court of Appeals for the Ninth Circuit, but were remanded back to the NLRB after the U.S. Supreme Court's decision in Noel Canning, 573 U.S., 134 S.Ct. 2550 (2014). On November 26, 2014, the NLRB found that a certification of representative should be issued. In January 2015, the parties submitted briefing to the NLRB as to whether summary judgment is appropriate. PGV currently expects a decision in this matter will be rendered within the next two to four months. Depending on the decision, PGV expects to review its options and either accept negotiations with the Union or continue to appeal the decision.

In January 2014, Ormat learned that two former employees alleged in a "qui tam" complaint filed in the United States District Court for the Southern District of California that us, PGV and select affiliates of us (collectively, the "Ormat Parties") submitted fraudulent applications and certifications to obtain grants. The United States Department of Justice has declined to intervene. The former employees have proceeded on their own and served the Ormat Parties with their initial complaint in April 2014, and then filed an amended complaint in May 2014. Pursuant to the Ormat Parties' motion to move the venue of the proceeding, and despite the complainants' objection, the file was reassigned from the United States District Court for the Southern District of California to the District of Nevada.

In July 2014, the Ormat Parties filed a motion to dismiss the amended complaint, in response to which the complainants have filed responses urging the court to reject the motion to dismiss. In August, 2014, the United States filed a statement of interest urging rejection of one of the Ormat Parties' arguments raised in the motion to dismiss - that the False Claims Act's "Tax Bar" excludes such Act's application to the case - while continuing to take no position as to the overall sufficiency of the complainants' complaint. The motion to dismiss remains pending before the Nevada United States District Court, and a hearing has been scheduled for March by the court.

In the interim, FIMI and Ormat Industries (both of who were originally named on the complaint, but were never served) have been removed from the complaint as co-defendants. The Ormat Parties continue to 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" since November 11, 2004. Prior to that, 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, 2015, there were 21 record holders of the Company's common stock. On February 25, 2015, our stock's closing price as reported on the NYSE was $32.62 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 therefore. 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 10 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 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

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, 2013 and 2014, and from January 1, 2015 until February 26, 2015:

	First Quarter 2013	Second Quarter 2013	Third Quarter 2013	Fourth Quarter 2013	First Quarter 2014	Second Quarter 2014	Third Quarter 2014	Fourth Quarter 2014	January 1 to February 26, 2015
High	$ 22	$ 24	$ 28	$ 28	$ 30	$ 30	$ 29	$ 29	$ 33
Low	$ 20	$ 20	$ 23	$ 25	$ 24	$ 26	$ 25	$ 26	$ 26

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, 2014 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, 2014

	11/11/2004	12/31/2004	12/31/2005	12/31/2006	12/31/2007	12/31/2008	12/31/2009	12/31/2010	12/31/2011	12/31/20
Ormat Technologies Inc	0%	9%	74%	145%	267%	112%	152%	97%	20%	29%
Standard & Poor's Composite 500 Index	0%	8%	11%	26%	31%	-20%	-1%	12%	12%	27%
^NEX -Wilder Hill new Energy Global	0%	9%	30%	74%	174%	7%	50%	28%	-23%	-28%
IPP Peers*	0%	22%	26%	79%	79%	77%	107%	119%	131%	165%
Renewable Peers**	0%	41%	19%	63%	204%	20%	45%	-25%	-22%	-30%

* 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.

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, 2014, 2013 and 2012 and as of December 31, 2014 and 2013 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, 2011 and 2010 and as of December 31, 2012, 2011 and 2010 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,				
	2014	**2013**	**2012**	**2011**	**2010**
	(Dollars in thousands, except per share data)				
Statements of Operations Data:					
Revenues:					
Electricity	$382,301	$329,747	$314,894	$312,296	$279,947
Product	177,223	203,492	186,879	113,160	81,410
Total revenues	559,524	533,239	501,773	425,456	361,357
Cost of revenues:					
Electricity	246,630	232,874	237,415	235,609	233,894
Product	109,143	140,547	135,346	76,072	53,277
Total cost of revenues	355,773	373,421	372,761	311,681	287,171
Gross margin	203,751	159,818	129,012	113,775	74,186
Operating expenses:					
Research and development expenses	783	4,965	6,108	8,801	10,120
Selling and marketing expenses	15,425	24,613	15,718	16,053	13,302
General and administrative expenses	28,614	29,188	28,066	27,366	26,937
Impairment charge	—	—	236,377	—	—
Write-off of unsuccessful exploration activities	15,439	4,094	2,639	—	3,050
Operating income (loss)	143,490	96,958	(159,896)	61,555	20,777
Other income (expense):					
Interest income	312	1,332	1,201	1,427	343
Interest expense, net	(84,654)	(73,776)	(64,069)	(69,459)	(40,473)
Foreign currency translation and transaction gains (losses)	(5,839)	5,085	242	(1,350)	1,557
Income attributable to sale of tax benefits	24,143	19,945	10,127	11,474	8,729
Gain from sale of property, plant and equipment	7,628	—	—	—	36,928
Gain from extinguishment of liability	—	—	—	—	—
Other non-operating income, net	756	1,592	590	671	130
	85,836	51,136	(211,805)	4,318	27,991

Income (loss) from continuing operations, before income taxes and equity in income (losses) of investees					
Income tax benefit (provision)	(27,608)	(13,552)	(1,827)	(48,240)	1,700
Equity in losses of investees, net	(3,213)	(250)	(2,522)	(959)	998
Income (loss) from continuing operations	55,015	37,334	(216,154)	(44,881)	30,689
Discontinued operations:					
Income from discontinued operations (including gain on disposal of $0, $3,646, $0, $0, and $6,336 respectively)	—	5,311	4,811	2,452	9,141
Income tax provision	—	(614)	(1,264)	(295)	(2,602)
Total income from discontinued operations	—	4,697	3,547	2,157	6,539
Net income (loss)	55,015	42,031	(212,607)	(42,724)	37,228
Net loss (income) attributable to noncontrolling interest	(833)	(793)	(414)	(332)	90
Net income (loss) attributable to the Company's stockholders	$54,182	$41,238	$(213,021)	$(43,056)	$37,318

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	Year Ended December 31,				
	2014	**2013**	**2012**	**2011**	**2010**
	(Dollars in thousands, except per share data)				
Earnings (loss) per share attributable to the Company's stockholders:					
Basic:					
Income (loss) from continuing operations	$1.19	$0.81	$(4.77)	$(1.00)	$0.67
Discontinued operations	—	0.10	0.08	0.05	0.15
Net income (loss)	$1.19	$0.91	$(4.69)	$(0.95)	$0.82
Diluted:					
Income (loss) from continuing operations	$1.18	$0.81	$(4.77)	$(1.00)	$0.67
Discontinued operations	—	0.10	0.08	0.05	0.15
Net income (loss)	$1.18	$0.91	$(4.69)	$(0.95)	$0.82
Weighted average number of shares used in computation of earnings (loss) per share attributable to the Company's stockholders:					
Basic	45,508	45,440	45,431	45,431	45,431
Diluted	45,859	45,475	45,431	45,431	45,452
Dividend per share declared	$0.21	$0.08	$0.08	$0.13	$0.27
Balance Sheet Data (at end of year):					
Cash and cash equivalents	$40,230	57,354	66,628	99,886	82,815
Working capital	68,121	103,001	64,100	98,415	66,932
Property, plant and equipment, net (including construction-in process)	1,734,359	1,741,163	1,649,014	1,889,083	1,696,101
Total assets	2,121,556	2,159,433	2,087,523	2,314,718	2,043,328
Long-term debt (including current portion)	1,001,410	1,077,857	1,030,928	1,025,010	789,669
Equity	786,746	745,111	695,607	906,644	945,227

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. We design, develop, build, sell, own, and operate clean, environmentally friendly geothermal and recovered energy-based power plants, in most cases 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 all of our recovered energy-based plants have been constructed by us. We 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 United States 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 United States and throughout the world. Our current generating portfolio includes geothermal plants in the United States, Guatemala, and Kenya, as well as REG plants in the United States.

For the year ended December 31, 2014, our total revenues increased by 4.9% (from $533.2 million to $559.5 million) over the previous year.

For the year ended December 31, 2014, Electricity Segment revenues were $382.3 million, compared to $329.7 million for the year ended December 31, 2013, an increase of 15.9%, and Product Segment revenues for the year ended December 31, 2014 were $177.2 million, compared to $203.5 million during the year ended December 31, 2013, a decrease of 12.9%.

During the years ended December 31, 2014 and 2013, our consolidated power plants generated 4,450,910 MWh and 4,253,489 MWh, respectively, an increase of 4.6%

For the year ended December 31, 2014, our Electricity Segment represented approximately 68.3% of our total revenues (61.8% in 2013), while our Product Segment represented approximately 31.7% of our total revenues (38.2% in 2013).

In the year ended December 31, 2014, approximately 70.0% of our Electricity Segment revenues were derived 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, the Heber 1 and Heber 2 power plants 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, by entering into derivatives transactions. In the year ended December 31, 2014, we recorded a gain of $5.7 million in electricity revenues related to these transactions.

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.

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, and such assets are not generally available to pay the corporate debt (other than debt at the respective project subsidiary level). However, these project subsidiaries are allowed to pay dividends and make distributions to us of all available and unrestricted cash flows generated by their assets.

Revenues attributable to our Product Segment are based on the sale of equipment and the provision of various services to our customers. These revenues may vary from period to period because of the timing of our receipt of purchase orders and the progress of our execution of each project.

Our management assesses the performance of our two segments of operation differently. In the case of our Electricity Segment, when making decisions about potential acquisitions or the development of new projects, we typically focus on the internal rate of return of the relevant investment, technical and geological matters and other business considerations. We evaluate our operating power plants based on revenues and expenses, and our projects that are under development based on costs attributable to each such project. We evaluate 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 United States 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 United States as costs for electricity generated from geothermal resources have become more competitive. Recently, 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). In response, the geothermal industry in the United States 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 United States will be driven by further commitment and implementation of renewable portfolio standards as well as the introduction of additional tax incentives. 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 and in other forms of clean energy.

Our focus continues to be organic growth through exploration, development, construction of new projects and enhancements of existing power plants along with increasing operational efficiency of our operating portfolio. We expect that our investment in organic growth will increase our total generating capacity, consolidated revenues and operating income attributable to our Electricity Segment from year to year. In addition, we routinely look at acquisition opportunities.

The continued awareness of climate change may result in significant changes in the business and regulatory environments, which may create business opportunities for us. In 2011, the first phase of the EPA "Tailoring Rule" took effect. The Tailoring Rule sets thresholds addressing the applicability of the permitting requirements under the Clean Air Act's Prevention of Significant Deterioration and Title V programs to certain major sources of GHG emissions. On June 23, 2014, the United States Supreme Court issued its decision in *Utility Air Regulatory Group v. Environmental Protection Agency et al.,* No. 12-1146, in part addressing the Tailoring Rule. As a result of this decision, the EPA can no longer require stationary sources of greenhouse gas emissions to comply with requirements under the Clean Air Act's Prevention of Significant Deterioration and Title V programs solely because of emissions of greenhouse gases. Since the court also held that the EPA lacked the authority to interpret the Clean Air Act's and issue the Tailoring Rule, the EPA must formally adopt thresholds triggering application of the Clean Air Act's Prevention of Significant Deterioration and Title V programs to stationary sources of greenhouse gas emissions that are subject to these programs in any event because of emissions of conventional pollutants. Different states have begun examining the effect of this decision on their applicable air emissions regulations. In addition to future establishment of these thresholds, federal legislation or additional federal regulations addressing climate change may be enacted.

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. 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 greenhouse gas emissions under AB 32. In addition to California, twenty U.S. states have set GHG emissions reduction targets and two states have reduction goals. Regional initiatives, such as the Western Climate Initiative (which includes California and four Canadian provinces) and the Midwest GHG Reduction Accord (which includes six U.S. states and one Canadian province), are also being developed to reduce GHG emissions and develop trading systems for renewable energy credits. In the United States, 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, the California Senate Bill X1-2 (SBX1-2) was signed into law, and increased California's RPS to 33% by December 31, 2020 and instituted a tradable REC program. SBX1-2 is expected to foster a liquid tradable REC market and lead to more creative off-take arrangements. Although we cannot predict at this time whether the tradable REC program under SBX1-2 and its implementing regulations will have a significant impact on our operations or revenue, it may facilitate additional options when negotiating PPAs and selling electricity from our projects.

In June 2013, the Nevada state legislature passed three bills that were signed by Nevada's Governor and are expected to support renewable energy development in the state. Senate bill (SB) No. 123 calls 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. Senate Bill 252 revises provisions relating to the renewable portfolio standard by removing energy efficiency, solar multipliers, and station usage from generating portfolio energy credits. Finally, Assembly Bill (AB) No. 239 Revised Statutes 701A.340 defines geothermal energy as renewable energy for purposes of tax abatements and makes geothermal projects eligible for partial sales and property tax abatements, with property tax abatements for a period of twenty years and local sales and use tax abatements for three years. In September 26, 2014 Governor Brown signed into law Assembly Bill No. 2363 (AB-2363), which requires the California Public Utilities Commission to adopt, by December 31, 2015, a methodology for determining the costs of integrating eligible renewable energy resources.

Outside of the United States, in November 2012, the United States, 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 United States will invest $7.0 billion in Sub-Saharan Africa over the following five years, with the aim of doubling access to power. The Sub-Sahara 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 applicable 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 competition from the wind and solar power generation industry to continue. 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 may contribute to a reduction in electricity prices. Despite increased competition from the wind and solar 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 resource. Also, geothermal power plants positively impact electrical grid stability and provide valuable ancillary services because of their base load nature while the intermittent renewables create integration costs. In the geothermal industry, we are experiencing a notable decrease in competition, specifically in the acquisition of geothermal leases. The reduced level of competition has contributed to a decrease in lease costs.

In the Product Segment, we expect 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 impact our profitability.

The changing natural gas landscape, the resulting effect on natural gas pricing (in either direction) and the corresponding implications for electric utilities and other producers of electricity in terms of planning for and choosing a source of fuel, will affect the pricing under our PPAs that have SRAC pricing, as described below.

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 recently signed a fixed rate PPAs for the rest of the complex. In the meantime, we have entered into put and swap contracts to reduce our exposure to fluctuations in the energy rate caused by fluctuations in oil prices through December 31, 2014. Our use of derivative instruments for this purpose has increased, and may continue to be used to manage our economic exposure.

Our Puna Complex is located in the Puna District on the Big Island, Hawaii, which is the general area that has been impacted by the eruption of Klauea active volcano in June 27, 2014 and the resulting lave flow and continuing volcanic activity since then. Our power plants at the Puna Complex were not directly affected by the volcanic eruption and the resulting lava flow however, the uncertainties regarding the potential impact of the lava flow on the transmission lines owned and maintained by HELCO (our power purchaser) necessitated contingency planning and cooperation with HELCO in anticipation of a possible loss of transmission capacity. As of the date of this Annual Report on Form 10-K, Helco has implemented several measures to protect the two transmission lines over which power generated by the Puna complex is transmitted to the grid from the extreme heat generated by the lava flow passing through and around the transmission poles. As a result, our power plant was not affected from the lava flow and the transmission lines are operating at regular capacity. It is impossible to predict whether the lava flow or other new or recurring volcanic activity may subsequently adversely impact the operation of our Puna complex and the operational integrity of the transmission poles and the transmission lines. Our Puna complex revenues consist of capacity payments and energy payments from HELCO. In the event of declared force majeure, HELCO is required to continue to make capacity payments but is not required to make energy payments to the extent the force majeure event precludes us from delivering, or HELCO from accepting, the energy. Loss of energy payments under the Puna PPAs would have an adverse effect on our financial performance. Revenues generated by the Puna Complex comprised 7.9% of our total revenues in 2014.

We had PPAs for the Ormesa, Mammoth and Heber complexes for a total of 161 MW that were fixed until May 1, 2012. Thereafter, the energy price component under these PPAs changed from a fixed rate to a variable rate based on SRAC pricing that is impacted by natural gas prices. In 2013, we signed new fixed rate PPAs that reduced our current exposure to SRAC by 18 MW and by additional 44 MW in 2016. We have entered into derivative transactions at a fixed price of $4.07 per MMbtu for the year 2014 to reduce further our exposure to fluctuations in natural gas prices through December 31, 2014 and $4.95 per MMbtu for the period from January 1, 2015 until March 31, 2015. Our use of derivative instruments for this purpose has increased, and likely will continue to be used to manage our economic exposure.

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, hostility, 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. 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 in the quarter ended September 30, 2014, under the supply contract we signed with the EPC contractor. 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. The Sarulla project's future operations may be impacted by various factors which we do not control given our minority position in the consortium, as well as other factors discussed above under "Risk Factors".

FERC is allowed under PURPA to terminate, upon the request of a utility, the obligation of electric utilities 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. The legislation does not affect existing PPAs. We do not expect this change in law to affect our U.S. power plants significantly, as all of our current PPAs are long-term. 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 70.0% of our Electricity revenues for the year ended December 31, 2014 were derived from PPAs with fixed price components, we have variable price PPAs in California and Hawaii. Our 143 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. In each of 2013 and 2014, we entered into derivative transactions in an attempt to reduce our exposure to fluctuations in the prices of oil from Puna's PPAs until December 31, 2014, and natural gas from California SO#4 PPAs until March 31, 2015.

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 and the status and timing of such orders. 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 2012 and 2013, 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 26, 2015, 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,		
	2014	**2013**	**2012**	**2014**	**2013**	**2012**
Revenues:						
Electricity	$382,301	$329,747	$314,894	68.3 %	61.8 %	62.8 %
Product	177,223	203,492	186,879	31.7	38.2	37.2
Total revenues	$559,524	$533,239	$501,773	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,		
	2014	**2013**	**2012**	**2014**	**2013**	**2012**
Electricity Segment:						
United States	$268,198	$246,112	$246,070	70.2 %	74.6 %	78.1 %
Foreign	114,103	83,635	68,824	29.8	25.4	21.9
Total	$382,301	$329,747	$314,894	100.0%	100.0%	100.0%
Product Segment:						
United States	$17,000	$55,101	$21,374	9.6 %	27.1 %	11.4 %
Foreign	160,223	148,391	165,505	90.4	72.9	88.6
Total	$177,223	$203,492	$186,879	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 Pacific Gas & Electric in California for the Heber 1 and 2 power plants 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 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 our energy revenues. However, the higher payments payable by Southern California Edison and Pacific Gas & Electric Company in the summer months have a more significant impact on our revenues than that of the higher energy revenues generally generated in winter due to increased efficiency. As a result, our electricity revenues are generally higher in the summer than in the winter.

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. 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 paid as a percentage of the revenues derived from the associated geothermal rights. Royalties constituted approximately 4.3% and 4.2% of Electricity Segment revenues for the years ended December 31, 2014 and December 31, 2013, 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, 2014 decreased to $40.2 million from $57.4 million as of December 31, 2013. This decrease is principally due to: (i) our use of $158.8 million to fund capital expenditures; (ii) a net change in restricted cash and cash equivalents of $42.2 million; (iii) $12.9 million of cash used to repurchase portion of Ormat Funding LLC (OFC) Senior Secured Notes; (iv) net repayment of $91.7 million used under our revolving credit lines with commercial banks; (v) repayment of $111.2 million of long-term debt; (vi) $11.3 million of cash paid to noncontrolling interest; and (vii) $9.6 million cash dividend paid. This decrease was partially offset by: (i) an additional $140.0 million of proceeds from 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 as described below under “Non-Recourse and Limited-Recourse Third-Party Debt”; (ii) $220.9 million derived from operating activities during the year ended December 31, 2014; (iii) cash grant of $27.4 million received 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 (iv) $35.3 million cash received from the sale of the Heber Solar plant. Our corporate borrowing capacity under committed lines of credit with different commercial banks as of December 31, 2014 was $555.2 million, as described below in “Liquidity and Capital Resources”, of which we have utilized $357.2 million as of December 31, 2014.

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 (such as legal fees) 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, 2014, and 2013, 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 $15,439,000 and $4,094,000 of capitalized costs during the years ended December 31, 2014 and 2013, 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 $73,431,000 and $69,639,000 at December 31, 2014 and 2013, respectively. Included in this amount, $26,618,000 and $30,141,000 relates to up-front bonus payments at December 31, 2014 and 2013, 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, 2014, 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.

The North Brawley geothermal power plant and the OREG 4 REG power plant were tested for impairment in 2012 and impairment charges were taken in 2012 for these plants as described in Note 6 of our consolidated financial statements.

- *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,		
	2014	**2013**	**2012 As Revised**
	(Dollars in thousands, except per share data)		
Statements of Operations Historical Data:			
Revenues:			
Electricity	$382,301	$329,747	$314,894
Product	177,223	203,492	186,879
	559,524	533,239	501,773
Cost of revenues:			
Electricity	246,630	232,874	237,415
Product	109,143	140,547	135,346
	355,773	373,421	372,761
Gross margin			
Electricity	135,671	96,873	77,479
Product	68,080	62,945	51,533
	203,751	159,818	129,012
Operating expenses:			
Research and development expenses	783	4,965	6,108
Selling and marketing expenses	15,425	24,613	15,718
General and administrative expenses	28,614	29,188	28,066
Impairment charge	—	—	236,377
Write-off of unsuccessful exploration activities	15,439	4,094	2,639
Operating income (loss)	143,490	96,958	(159,896)
Other income (expense):			
Interest income	312	1,332	1,201
Interest expense, net	(84,654)	(73,776)	(64,069)
Foreign currency translation and transaction gains (losses)	(5,839)	5,085	242
Income attributable to sale of tax benefits	24,143	19,945	10,127
Gain from sale of property, plant and equipment	7,628		
Other non-operating income, net	756	1,592	590
Income (loss) from continuing operations, before income taxes and equity in income of investees equity in income of investees	85,836	51,136	(211,805)
Income tax provision	(27,608)	(13,552)	(1,827)
Equity in losses of investees, net	(3,213)	(250)	(2,522)
Income (loss) from continuing operations	55,015	37,334	(216,154)
Discontinued operations:			

Income from discontinued operations (including gain on disposal of ,$0, $3,646 and $0, respectively)	—	5,311	4,811
Income tax provision	—	(614)	(1,264)
Total income from discontinued operations	—	4,697	3,547
Net income (loss)	55,015	42,031	(212,607)
Net loss attributable to noncontrolling interest	(833)	(793)	(414)
Net income (loss) attributable to the Company's stockholders	$54,182	$41,238	$(213,021)
Earnings (loss) per share attributable to the Company's stockholders:			
Basic:			
Income (loss) from continuing operations	$1.19	$0.81	$(4.77)
Discontinued operations	—	0.10	0.08
Net income (loss)	$1.19	$0.91	$(4.69)
Diluted:			
Income (loss) from continuing operations	$1.18	$0.81	$(4.77)
Discontinued operations	—	0.10	0.08
Net income (loss)	$1.18	$0.91	$(4.69)
Weighted average number of shares used in computation of earnings per share attributable to the Company's stockholders:			
Basic	45,623	45,440	45,431
Diluted	45,974	45,475	45,431

	Year Ended December 31, 2014	2013	2012
Statements of Operations Data:			
Revenues:			
Electricity	68.3 %	61.8 %	62.8 %
Product	31.7	38.2	37.2
	100.0	100.0	100.0
Cost of revenues:			
Electricity	64.5	70.6	75.4
Product	61.6	69.1	72.4
	63.6	70.0	74.3
Gross margin			
Electricity	35.5	29.4	24.6
Product	38.4	30.9	27.6
	36.4	30.0	25.7
Operating expenses:			
Research and development expenses	0.1	0.9	1.2
Selling and marketing expenses	2.8	4.6	3.1
General and administrative expenses	5.1	5.5	5.6
Impairment charge	0.0	0.0	47.1
Write-off of unsuccessful exploration activities	2.8	0.8	0.5
Operating income (loss)	25.6	18.2	(31.9)
Other income (expense):			
Interest income	0.1	0.2	0.2
Interest expense, net	(15.1)	(13.8)	(12.8)
Foreign currency translation and transaction gains (losses)	(1.0)	1.0	0.0
Income attributable to sale of tax benefits	4.3	3.7	2.0
Other non-operating income, net	0.1	0.3	0.1
Income (loss) from continuing operations, before income taxes and equity in income of investees	15.3	9.6	(42.2)
Income tax provision	(4.9)	(2.5)	(0.4)
Equity in losses of investees, net	(0.6)	(0.0)	(0.5)
Income (loss) from continuing operations	9.8	7.0	(43.1)
Discontinued operations:			
Income from discontinued operations (including gain on disposal of ,$0, $3,646 and $0, respectively)	0.0	1.0	1.0
Income tax provision	0.0	(0.1)	(0.3)
Total income from discontinued operations	0.0	0.9	0.7
Net income (loss)	9.8	7.9	(42.4)
Net loss attributable to noncontrolling interest	(0.1)	(0.1)	(0.1)
Net income (loss) attributable to the Company's stockholders	9.7 %	7.7 %	(42.5)%

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, which represented a 4.9% increase in total revenues. This increase was attributable to our Electricity Segment, in which revenues increased by 15.9% over the corresponding period in 2013. This increase was offset due to a 12.9% decrease in our Product Segment 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, which represented a 15.9% increase in such revenues. 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 power plant in Nevada, which commenced commercial operation 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 4,253,489 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, which represented a 12.9% decrease. This decrease in our Product Segment revenues 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, which represented a 4.7% decrease. This decrease was primarily due to the decrease in cost of revenues from our Product Segment. The decrease was partially offset due to 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, which represented a 5.9% increase. 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, which represented a 22.3% decrease. This decrease was primarily due 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. The 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 manufacturing enhancements that we effected during the year.

Research and Development Expenses

Research and development expenses excluding grants from the U.S Department of Energy 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 U.S Department of Energy in the amount of $0.5 million and $1.6 million for the years ended December 31, 2014 and 2013, respectively, related to the Enhanced Geothermal Systems 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. The 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 due to 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 operation. 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, an increase of 48.0%. The increase in operating income was principally 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. This increase was partially offset due to 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 $10.9 million increase was primarily due to: the conversion in July 2013 of OPIC interest loans from floating interest rate to fixed interest rate; and 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 the 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 three months ended March 31, 2014, in the amount of $2.2 million related to the ORTP transaction which represented 25% of the value of PTC's generated.

Gain from sale of Property, Plant and Equipment

Gain from 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 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 United States. 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 $251.4 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 24 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. In 2015 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 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 in 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, an increase of 47.4%. 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 sale of property, plant and equipment; and (iii) a $4.2 million increase in income attributable to 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. The operations of MPC for the year ended December 31, 2013, have been 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, which represents an increase of $13.0 million, a 30.9% increase. The increase in net income was principally attributable to the increase in income from continuing operations, as discussed above.

Comparison of the Year Ended December 31, 2013 and the Year Ended December 31, 2012

Total Revenues

Total revenues for the year ended December 31, 2013 were $533.2 million, compared to $501.8 million for the year ended December 31, 2012, which represented a 6.3% increase in total revenues. This increase was attributable to both our Product and Electricity Segments, in which revenues increased by 8.9% and 4.7%, respectively, over the corresponding period in 2012.

Electricity Segment

Revenues attributable to our Electricity Segment for the year ended December 31, 2013 were $329.7 million, compared to $314.9 million for the year ended December 31, 2012, which represented a 4.7% increase in such revenues. This increase was primarily due to a $37.3 million increase in revenues from our: (i) Olkaria III Plant 2, which commenced commercial operation at the beginning of May 2013; (ii) a full year of operations of the McGinness Hills power plant in 2013 compared to only six months in 2012; and (iii) Tuscarora power plant, which started to receive commercial rates in the second quarter of 2012. This increase was partially offset by: (i) an $11.0 million decrease resulting from the impact of natural gas prices on the energy rates in our SO#4 PPAs in California, which at the beginning of May 2012 changed from a fixed rate to a variable rate; (ii) a $4.5 million net decrease due to reduced generation in some of our power plants and a reduction in energy rates in our Puna and Amatitlan power plants; and (iii) a net loss of $5.0 million on derivative contracts on oil and natural gas prices, compared to a net gain of $2.1 million over the corresponding period in 2012. Power generation in our power plants increased by 7.9% from 3,942,293 MWh in the year ended December 31, 2012 to 4,253,489 MWh in the year ended December 31, 2013.

Product Segment

Revenues attributable to our Product Segment for the year ended December 31, 2013 were $203.5 million, compared to $186.9 million for the year ended December 31, 2012, which represented an 8.9% increase. The increase in our Product Segment revenues reflects the increase in new customer orders that we secured in 2012 and 2013.

Total Cost of Revenues

Total cost of revenues for the year ended December 31, 2013 was $373.4 million, compared to $372.8 million for the year ended December 31, 2012. As a percentage of total revenues, our total cost of revenues for the year ended December 31, 2013 decreased to 70.0%, compared to 74.3% for the year ended December 31, 2012. The decrease was attributable to a decrease in cost of revenues in our Electricity offset by an increase in our Product Segments.

Electricity Segment

Total cost of revenues attributable to our Electricity Segment for the year ended December 31, 2013 was $232.9 million, compared to $237.4 million for the year ended December 31, 2012, which represented a 1.9% decrease. This decrease was primarily due to a decrease in depreciation in our: (i) North Brawley power plant as a result of an impairment for the plant we recorded in the fourth quarter of 2012 and (ii) Mammoth complex, due to fully depreciating a portion of its equipment in previous periods as a result of the planned refurbishment and purchase of new equipment. The decrease was primarily offset by additional cost of revenues from our new plants, the Olkaria III Plant 2, which commenced commercial operation at the beginning of May 2013 and McGinness Hills power plant, which commenced commercial operations in July 2012. As a percentage of total electricity revenues, the total cost of revenues attributable to our Electricity Segment for the year ended December 31, 2013 was 70.6%, compared to 75.4% for the year ended December 31, 2012.

Product Segment

Total cost of revenues attributable to our Product Segment for the year ended December 31, 2013 was $140.5 million, compared to $135.3 million for the year ended December 31, 2012, which represented a 3.8% increase. As a percentage of total Product Segment revenues, our total cost of revenues attributable to the Product Segment for the year ended December 31, 2013 was 69.1%, compared to 72.4% for the year ended December 31, 2012. The 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.

Research and Development Expenses

Research and development expenses for the year ended December 31, 2013 were $5.0 million, compared to $6.1 million for the year ended December 31, 2012, which represented an 18.7% decrease. The research and development expenses are net of grants from the DOE in the amount of $1.6 million and $0.7 million for the years ended December 31, 2013 and 2012, respectively, with respect to the EGS project.

Selling and Marketing Expenses

Selling and marketing expenses for the year ended December 31, 2013 were $24.6 million, compared to $15.7 million for the year ended December 31, 2012, which represented a 56.6% increase. The increase was primarily due to a one-time early termination fee in the amount of $9.0 million we paid to SCE relating to the termination of the PPAs for the G1 and G3 power plants in the Mammoth complex, as described under Item 1 – "Business" and from a $2.6 million termination fee paid to NV Energy related to the termination of the Dixie Meadows PPA. The increase was partially offset by lower 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, 2013 constituted 2.4% of total revenues for such year, compared to 3.1% of such revenues for the year ended December 31, 2012.

General and Administrative Expenses

General and administrative expenses for the year ended December 31, 2013 were $29.2 million, compared to $28.1 million for the year ended December 31, 2012. General and administrative expenses for the year ended December 31, 2013, constituted 5.5% of total revenues for such year, compared to 5.6% for the year ended December 31, 2012.

Impairment Charges

There were no impairment charges for the year ended December 31, 2013. The impairment charges for the year ended December 31, 2012 were $236.4 million.

Write-off of Unsuccessful Exploration Activities

Write-off of unsuccessful exploration activities for the year ended December 31, 2013 was $4.1 million compared to $2.6 million for the year ended December 31, 2012. 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. Write-off of unsuccessful exploration activities for the year ended December 31, 2012 represented the write-off of exploration costs (including land costs) related to five exploration sites in Nevada that we determined in the year ended December 31, 2012 would not support commercial operations.

Operating Income (Loss)

Operating income for the year ended December 31, 2013 was $97.0 million, compared to operating loss of $159.9 million for the year ended December 31, 2012. The increase in operating income was principally attributable to: (i) the impairment charges for the year ended December 31, 2012 in the total amount of $236.4 million, as described above; and (ii) the increased gross margins in both our electricity and product segments as discussed above. The increase was partially offset due to the one-time early termination fees of $11.6 million included in selling and marketing expenses discussed above. Operating income attributable to our Electricity Segment for the year ended December 31, 2013 was $54.3 million, compared to operating loss of $190.0 million for the year ended December 31, 2012. Operating income attributable to our Product Segment for the year ended December 31, 2013 was $42.7 million, compared to $30.1 million for the year ended December 31, 2012.

Interest Expense, Net

Interest expense, net, for the year ended December 31, 2013 was $73.8 million, compared to $64.1 million for the year ended December 31, 2012, which represented a 15.2% increase. This $9.7 million increase was primarily due to an increase of $6.9 million in interest expense related to the sale of tax benefits, and a $4.4 million decrease related to interest capitalized to our projects under development and construction.

Foreign Currency Translation and Transaction Gains

Foreign currency translations and transaction used to cover our foreign exchange exposure, resulted in gains for the year ended December 31, 2013 of $5.1 million, compared to $0.2 million for the year ended December 31, 2012. The increase was primarily due to gains on foreign currency forward contracts for the year ended December 31, 2013, 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” below) for the year ended December 31, 2013 was $19.9 million, compared to $10.1 million for the year ended December 31, 2012. This income represents the value of PTCs and taxable income or loss generated by OPC and ORTP and allocated to the investors in the amount of $5.4 million and $14.5 million, respectively, in the year ended December 31, 2013, compared to PTCs and taxable income or loss generated by OPC and allocated to the investors in the year ended December 31, 2012.

Income Taxes

Income tax provision for the year ended December 31, 2013 was $13.6 million, compared to $1.8 million for the year ended December 31, 2012. 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, 2013 and 2012, was 26.5% and 0.9%, respectively. The effective tax rate differs from the federal statutory rate of 35% for the year ended December 31, 2013, primarily due to unbenefited losses in the U.S. and certain foreign jurisdictions.

For the year ended December 31, 2013 and 2012, we recorded a valuation allowance in the amount of approximately $112.1 million and $113.6 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, 2013 we had U.S. federal NOLs in the amount of approximately $235.4 million, state NOLs in the amount of approximately $218.1 million, and unutilized tax credits of approximately $71.3 million, all of which can be carried forward for 20 years. The related deferred tax assets totaled approximately $112.1 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 $112.1 million was recorded against the U.S. deferred tax assets as of December 31, 2013 as at that point in time, we believed it is more likely than not that the deferred tax assets will not be realized.

Income (Loss) from Continuing Operations

Income from continuing operations for the year ended December 31, 2013 was $37.3 million, compared to a loss from continuing operations of $216.2 million for the year ended December 31, 2012. The increase in income from continuing operations of $253.6 million was principally attributable to (i) a $256.3 million increase in operating income, as discussed above; (ii) a $4.8 million increase in foreign currency translation and transaction gains; and (iii) a $9.8 million increase in income attributable to sale of tax benefits. This increase was offset partially by a $9.6 million increase in interest expense, net, and $11.1 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. The operations of MPC for the year ended December 31, 2012, have been included in discontinued operations. Discontinued operations for the years ended December 31, 2013 and 2012 include revenues of $4.9 million and $12.6 million, respectively of MPC.

Net Income (Loss)

Net income for the year ended December 31, 2013 was $42.0 million, compared to net loss of $212.6 million for the year ended December 31, 2012. The increase in net income of $254.7 million was principally attributable to a $253.6 million 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 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, 2014, we had access to the following sources of funds: (i) $40.2 million in cash, cash equivalents of which $33.5 million is related to foreign jurisdictions; and (ii) $198.0 million of unused corporate borrowing capacity under existing lines of credit with different commercial banks.

Our estimated capital needs for 2015 include approximately $250.0 million for capital expenditures on new projects under development or construction, exploration activity, operating projects, and machinery and equipment, as well as $71.5 million for debt repayment.

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.

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 these sources will address our anticipated liquidity, capital expenditures, and other investment requirements.

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, one of our subsidiaries, 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, 2014, the last measurement date of the covenants, the actual historical 12-month DSCR was 1.28 and the pro-forma 12-month DSCR was 1.31 (on a semi-annual basis and as of December 31, 2014). There were $67.2 million of OFC Senior Secured Notes outstanding as of December 31, 2014.

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In January 2014, we acquired from OFC noteholders OFC Senior Secured Notes with an outstanding aggregate principal amount of $13.2 million. We recognized a gain of $0.3 million in the year ended December 31, 2014. In February 2013, we acquired from OFC noteholders OFC Senior Secured Notes with an outstanding aggregate principal amount of $12.8 million and we recognized a gain of $0.8 million in the year ended December 31, 2013.

OrCal Geothermal Senior Secured Notes — Non-Recourse

In December, 2005, OrCal, one of our subsidiaries, issued $165.0 million of OrCal Senior Secured Notes for the purpose of refinancing the acquisition cost of the Heber complex. The OrCal Senior Secured Notes have been 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, 2014, the last measurement date of the covenants, the actual historical 12-month DSCR was 1.28, and the pro-forma 12-months DSCR was 1.29. There were $55.1 million of OrCal Senior Secured Notes outstanding as of December 31, 2014.

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

In September 2011, OFC 2, one of our subsidiaries, 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, 2014, we have utilized $291.7 million of the 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 in 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 signed a $140.0 million loan under the 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. Department of Energy Loan Programs Office in accordance with and subject to the Department'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 Notes, which include loans for the Tuscarora, Jersey Valley and McGinness Hills complexes, are rated "BBB" by Standard & Poor's.

In connection with the anticipation drawdown, on August 13, 2014, we entered into an on-the-run interest lock agreement with a financial institution with a termination date of 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 in the annual interest rate of 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 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, 2014, the last measurement date of the covenants, the actual DSCR was 1.62 and the pro-forma 12-month DSCR was 2.24. There were $272.5 million of OFC 2 Senior Secured Notes outstanding as of December 31, 2014.

We provided a guarantee in connection with the issuance of the Series A and C 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, one of our subsidiaries, entered into a finance agreement with OPIC, an agency of the United States 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 as of December 31, 2014, of $75.5 million and matures on December 15, 2030 and Tranche II, which has an outstanding balance as of December 31, 2014, of $164.1 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 as of December 31, 2014, of $43.0 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 $31.6 million as of December 31, 2014, has been subordinated to the OPIC Loan.

There are various restrictive covenants under the OPIC Loan, which include 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 ratios 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, 2014, the actual historical and projected 12-month DSCR was 2.05 and 1.94, respectively.

As of December 31, 2014, $282.6 million of the above loan was outstanding.

Amatitlan Loan — Non-Recourse

In May 2009, Ortitlan, one of our subsidiaries, entered into a note purchase agreement in an aggregate principal amount of $42.0 million which refinanced its investment in the 20 MW geothermal power plant located in Amatitlan, Guatemala. The loan was provided by EIG Global Project Fund II, Ltd. (formerly TCW). On September 30, 2014, we repaid the loan in full from corporate funds. The outstanding amount at the time of repayment was approximately $30.0 million. We are currently negotiating a new financing agreement that we believe will contain improved terms.

Full-Recourse Third-Party Debt

Union Bank. In February 2012, Ormat Nevada, our wholly owned subsidiary 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, which was subsequently extended to May 20, 2015. 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 parties thereto. 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, 2014: (i) the actual 12-month debt to EBITDA ratio was 3.18; (ii) the 12-month DSCR was 2.45; and (iii) the distribution leverage ratio was 0.65. 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, 2014, letters of credit in the aggregate amount of $42.1 million remain issued and outstanding under this committed credit agreement with Union Bank.

HSBC. In May 2013, Ormat Nevada, our wholly owned subsidiary, entered into a credit agreement with HSBC Bank USA, N.A for one year with annual renewals, which was extended to May 31, 2015. 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 parties thereto. 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, 2013: (i) the actual 12-month debt to EBITDA ratio was 3.18; (ii) the 12-month DSCR was 2.45; and (iii) the distribution leverage ratio was 0.65. 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, 2014, letters of credit in the aggregate amount of $21.8 million remain issued and outstanding under this committed credit agreement.

Credit Agreements. We also have committed credit agreements with six other commercial banks for an aggregate amount of $480.2 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 $247.0 million; and (ii) the issuance of one or more letters of credit in the amount of up to $233.2 million. The credit agreements mature between end of March 2015 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, 2014, loans in the total amount of $20.3 million were outstanding, and letters of credit with an aggregate stated amount of $293.2 million were issued and outstanding under these credit agreements. The $20.3 million in loans are for terms of three months or less and bear interest at a weighted average rate of 2.30%.

Term Loans. We have a $20.0 million term loan with a group of institutional investors, which matures on July 16, 2015, is payable in 12 semi-annual installments commencing January 16, 2010, and bears interest of 6.5%. As of December 31, 2014, $3.9 million was outstanding under this loan.

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, 2014, $10.0 million was outstanding under this loan.

We have a $20.0 million term loan with a group of institutional investors, which matures on November 16, 2016, is payable in ten semi-annual installments commencing May 16, 2012, and bears interest of 5.75%. As of December 31, 2014, $8.0 million was outstanding under this loan.

We had a $50.0 million term loan with a commercial bank, which fully repaid on November 10, 2014. The loan was payable in ten semi-annual installments commencing May 10, 2010, and bore interest at 6-month LIBOR plus 3.25%.

Senior Unsecured Bonds. We have an aggregate principal amount of approximately $250.0 million of Senior Unsecured Bonds 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, the principal of the bonds 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, 2014, $31.6 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 in the total 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, 2014: (i) total equity was $786.7 million and the actual equity to total assets ratio was 37.1% and (ii) the 12-month debt, net of cash, cash equivalents, to Adjusted EBITDA ratio was 3.70. During the year ended December 31, 2014, we distributed interim dividends in an aggregate amount of $9.6 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, 2014, committed letters of credit in the aggregate amount of $357.2 million remained issued and outstanding under the credit agreements with Union Bank, HSBC and six 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 abovementioned 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 $2.2 million in the first quarter of 2014.

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 OERP. The 5.0% and 2.5% residual interest commences 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. This residual 5.0% and 2.5% interest represents a noncontrolling interest and is 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 $7.5 million as of December 31, 2014. 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**
August 8, 2013	0.04	August 19, 2013	August 29, 2013
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

Historical Cash Flows

The following table sets forth the components of our cash flows for the relevant periods indicated:

	Year Ended December 31,		
	2014	**2013**	**2012**
	(Dollars in thousands)		
Net cash provided by operating activities	$213,235	$86,760	$89,471
Net cash used in investing activities	(129,162)	(157,153)	(100,790)
Net cash provided by (used in) financing activities	(101,197)	61,119	(21,939)
Net change in cash and cash equivalents	(17,124)	(9,274)	(33,258)

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. The net 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) 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 noncontrolling interest; and (v) $9.6 million cash dividend paid, reduced by $140.0 million of proceeds from 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.

For the Year Ended December 31, 2013

Net cash provided by operating activities for the year ended December 31, 2013 was $86.8 million, compared to $89.5 million for the year ended December 31, 2012. The net decrease of $2.7 million resulted primarily from: (i) an increase in net income of $254.7 million from a net loss of $212.6 million in the year ended December 31, 2012 to net income of $42.0 million in the year ended December 31, 2013, as described above; (ii) an increase in deferred income tax provision, net of $9.2 million in the year ended December 31, 2013, compared to a decrease of $4.7 million in the year ended December 31, 2012. Such increase was partially offset by: (i) an impairment charge of $236.4 million, for the year ended December 31, 2012; (ii) a decrease in billing in excess of costs and estimated earnings on uncompleted contracts, net of $29.1 million in our Product Segment in the year ended December 31, 2013, compared to $13.3 million in the year ended December 31, 2012, as a result of timing in billing of our customers; and (iii) an increase in receivables of $37.2 million in the year ended December 31, 2013, compared to $3.6 million in the year ended December 31, 2012, as a result of timing of collections from our customers.

Net cash used in investing activities for the year ended December 31, 2013 was $157.2 million, compared to $100.8 million for the year ended December 31, 2012. The principal factors that affected our net cash used in investing activities during the year ended December 31, 2013 were capital expenditures of $204.6 million, primarily for our facilities under construction reduced by: (i) a net decrease of $25.5 million in restricted cash and cash equivalents; (ii) cash grant of $14.7 million received in the year ended December 31, 2013 from the U.S. Treasury under Section 1603 of the ARRA relating to the Brawley geothermal power plant; and (iii) the receipt of $7.7 million of cash from the sale of our interest in MPC.

Net cash provided by financing activities for the year ended December 31, 2013 was $61.1 million, compared to net cash used in financing activities of $21.9 million for the year ended December 31, 2012. The principal factors that affected the net cash provided by financing activities during the year ended December 31, 2013 were: (i) $90.0 million of net proceeds from the disbursement from Tranche II and III of the OPIC Loan, as described above under “Non-Recourse and Limited-Recourse Third-Party Debt”; (ii) $31.4 million of net proceeds from the ORTP Transaction (see “ORTP Transaction” above); (iii) a net increase of $38.4 million against our revolving lines of credit with commercial banks, reduced by: (i) $11.9 million of cash paid to repurchase our OFC Senior Secured Notes; (ii) the repayment of long-term debt in the amount of $68.4 million; (iii) $13.4 million of cash paid to the Class B membership units of OPC (see “OPC Transaction”); and (iv) the payment of a dividend to our shareholders in the amount of $3.6 million.

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 cost, (vi) stock-based compensation, and (vii) gain from extinguishment of liability. EBITDA and Adjusted EBITDA are not a measurement of financial performance or liquidity under accounting principles generally accepted in the United States of America 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 accounting principles generally accepted in the United States of America. 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 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, 2014 was $272.7 million, compared to $241.0 million for the year ended December 31, 2013 and $187.2 million for the year ended December 31, 2012.

The following table reconciles net cash provided by operating activities to EBITDA and adjusted EBITDA, for the years ended December 31, 2014, 2013, and 2012:

	Year Ended December 31,		
	2014	**2013**	**2012**
	(Dollars in thousands)		
Net cash provided by operating activities	$213,235	$86,760	$89,471
Adjusted for:			
Interest expense, net (excluding amortization of deferred financing costs)	76,970	67,677	57,711
Interest income	(312)	(1,332)	(1,201)
Income tax provision (benefit)	27,608	14,166	3,091
Minority interest in earnings of subsidiaries	-	-	-
Adjustments to reconcile net income to net cash provided by operating activities (excluding depreciation and amortization)	(57,422)	48,203	(199,738)
EBITDA	260,079	215,474	(50,666)
	(6,960)	7,813	(4,982)

Loss (gain) on derivatives which represent swap contracts on natural gas and oil prices			
Stock-based compensation	5,571	6,262	6,394
Gain on sale of subsidiary and property, plant and equipment	(7,628)	(3,646)	-
Termination fee	-	11,604	-
Share exchange transaction costs	1,000	-	-
Impairment charge	-	-	236,377
Write-off of insuccessful exploration activities	15,439	4,094	2,639
Loss (gain) on derivatives which represent currency forward contracts	5,172	(615)	(2,565)
Adjusted EBITDA	$272,673	$240,986	$187,197
Net cash used in investing activities	$(129,162)	$(157,153)	$(100,790)
Net cash provided by (used in) financing activities	$(101,197)	$61,119	$(21,939)

Capital Expenditures

Our capital expenditures primarily relate to two principal components: (i) the enhancement of our existing power plants; and (ii) the development and construction of new power plants.

We have estimated approximately $232.0 million in capital expenditures for construction of new projects, and for enhancement of our existing power plants, of which we have invested approximately $17.0 million as of December 31, 2014 and of which we expect to invest $153.0 million in 2015 and the remaining $67.0 million thereafter.

In addition, we estimate approximately $97.0 million in additional capital expenditures in 2015 to be allocated as follows: (i) $32.0 million in development of new projects; (ii) $16.0 million for enhancement of our operating power plants; (iii) $46.0 million in exploration activities in various leases for geothermal resources in which we have started the exploration activity; and (iv) $3.0 million in enhancement of our production facilities.

In the aggregate, we estimate our total capital expenditures for 2015 to be approximately $250.0 million.

Exposure to Market Risks

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.

One market risk to which power plants are typically exposed is the volatility of electricity prices. 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 PPAs of the Heber 1 and 2 power plants 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. Beginning in May 2012, the energy payments under the PPAs of the Heber 1 and 2 power plants 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 and March 2014, we entered into derivative transactions to reduce our exposure to the price of natural gas, under these PPAs, until March 31, 2015. 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 Hawaii Electric Light Company’s (HELCO’s) avoided costs. Likewise, in October 2013 we entered into a derivative transaction to reduce our exposure to the price of oil, under the 25 MW PPA of the Puna complex, until December 31, 2014.

As of December 31, 2014, 96.0% of our consolidated long-term debt comprised a fixed rate debt and therefore was not subject to interest rate volatility risk. As of such date, 4.0% of our long-term debt was in the form of a floating rate instrument, exposing us to changes in interest rates in connection therewith. As of December 31, 2014, $40.2 million of our long-term debt remained subject to some floating 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 market risk due to changes in interest rates. Fixed rate securities may have their market value adversely impacted due to a rise in interest rates, while floating rate securities may produce less income than expected if interest rates fall. Due in part to these factors, our future investment income may fall short of expectation due to changes in interest rates or we may suffer losses in principal if we are forced to sell securities that decline in market value due to changes in interest rates. However, because we classify our debt securities as “available-for-sale”, no gains or losses are recognized due to changes in interest rates unless such securities are sold prior to maturity or declines in fair value are determined to be other-than-temporary.

Another market risk to which we are exposed is potential adverse changes in foreign currency exchange rates, 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 sale 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, 2014 and 2013 by a hypothetical 10% and calculating the resulting change in the fair values.

The results of the sensitivity analysis calculations as of December 31, 2014 and 2013 are presented below:

	Assuming a 10% Increase in Rates		Assuming a 10% Decrease in Rates		
	As of December 31,		As of December 31,		
Risk	**2014**	**2013**	**2014**	**2013**	**Change in the Fair Value of**
	(Dollars in thousands)				
NGI Price	(685)	(3,522)	685	3522	NGI Swap
NYMEX Heating Oil Price	-	(3,442)	-	3,442	NYMEX HO2 Swap
Foreign Currency	(6,720)	(3,381)	1,809	4,133	Foreign Currency Forward Contracts
Interest Rate	(1,102)	(2,562)	1,129	3,557	Ormat Funding Corp. (“OFC”)
Interest Rate	(921)	(1,298)	945	1,650	Orcal Geothermal Inc. (“OrCal”)
Interest Rate	(10,155)	(5,519)	10,861	6,100	OFC 2 LLC (“OFC 2”)
Interest Rate	(244)	(379)	249	560	Loan from DEG
Interest Rate	(10,211)	(11,836)	10,825	-	Loan from OPIC
Interest Rate	-	(328)	-	468	Loan from TCW
Interest Rate	(3,336)	(4,349)	3,389	5,623	Senior unsecured bonds

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 mitigating factors against any inflation risk.

In connection with the Electricity Segment, inflation may directly impact an expense incurred for the operation of our projects, hence increasing the overall operating cost to us. 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 plant, 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 determined 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, hence increasing our operating costs in that segment. In this segment, it is more likely that we will be able to offset part or all of the inflationary impact through our project pricing. With respect to power plants that we construct 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, 2014 (in thousands):

	Payments Due By Period						
	Remaining Total	2015	2016	2017	2018	2019	Thereafter
Long-term liabilities principal	$1,001,410	$91,779	$69,060	$316,017	$59,186	$50,889	$414,479
Interest on long-term liabilities (1)	347,852	59,372	54,328	50,110	28,584	25,046	130,412
Future minimum operating lease	47,218	8,222	8,374	8,747	8,944	6,018	6,913
Benefits upon retirement (2)	16,579	4,109	665	2,163	2,518	821	6,303
Asset retirement obligation	19,142	—	—	—	—	—	19,142
Purchase commitments (3)	119,200	119,200	—	—	—	—	—
	$1,551,401	$282,682	$132,427	$377,037	$99,232	$82,774	$577,249

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(1) Interest on the OFC Senior Secured Notes due in 2020 is fixed at a rate of 8.25%. Interest on the OrCal Senior Secured Notes due in 2020 is fixed at a rate of 6.21%. Interest on the OFC 2 Senior Secured Notes Series A due in 2032 is fixed at a rate of 4.687%. Interest on the OPIC Loan due in 2030 is fixed at an average rate of 6.29%. Interest on the DEG Loan due in 2018 is fixed for $21.7 million as of December 31, 2014, at a rate of 6.9% and variable on the remaining balance (which as of December 31, 2014 was $9.9 million). Interest on a loan from institutional investors due in 2015 is fixed at a rate of 6.5%. Interest on a loan from institutional investors due in 2016 is fixed at a rate of 5.75%. Interest on the Senior Unsecured Bonds due in 2017 is fixed at a rate of 7%. Interest on the remaining debt is variable (based primarily on changes in LIBOR rates). For purposes of the above calculation of interest payments pertaining to variable rate debt, future LIBOR rates were based on constant maturity swaps.

(2) The above amounts were determined based on the employees’ current salary rates and the number of years’ service that will have been accumulated at their expected retirement date. These amounts do not include amounts that might be paid to employees that will cease working with us before reaching their expected retirement age.

(3) We purchase raw materials for inventories, construction-in-process and services from a variety of vendors. During the normal course of business, in order to manage manufacturing lead times and help assure adequate supply, we enter into agreements with contract manufacturers and suppliers that either allow them to procure goods and services based upon specifications defined by us, or that establish parameters defining our requirements. At December 31, 2015, total obligations related to such supplier agreements were approximately $119.2 million (approximately $44.1million of which relate to construction-in-process). All such obligations are payable in 2015.

The above table does not reflect unrecognized tax benefits of $7.5 million, the timing of which is uncertain. Refer to Note 18 to our consolidated financial statements set forth in Item 8 of this annual report for additional discussion of unrecognized tax benefits. The above table also does not reflect a liability associated with the sale of tax benefits of $39.0 million, the timing of which is uncertain. Refer to Note 12 to our consolidated financial statements as set forth in Item 8 of this annual report for additional discussion of our liability associated with the sale of tax benefits.

Concentration of Credit Risk

Our credit risk is currently concentrated with the following major customers: Southern California Edison, HELCO, KPLC and Sierra Pacific Power Company and Nevada Power Company (subsidiaries of NV Energy). If any of these electric utilities fails to make payments under its PPAs with us, such failure would have a material adverse impact on our financial condition.

Southern California Edison accounted for 13.5%, 14.2%, and 18.0% of our total revenues for the three years ended December 31, 2014, 2013, and 2012, respectively. Southern California Edison is also the power purchaser and revenue source for our Mammoth project, which we accounted for separately under the equity method of accounting through August 1, 2010.

Sierra Pacific Power Company and Nevada Power Company accounted for 16.5%, 17.6%, and 13.6% of our total revenues for the three years ended December 31, 2014, 2013, and 2012, respectively.

KPLC accounted for 15.4%, 11.6%, and 8.1% of our total revenues for the three years ended December 31, 2014, 2013, and 2012, respectively.

Government Grants and Tax Benefits

The U.S. government encourages production of electricity from geothermal resources through certain tax subsidies. If we started construction of a new geothermal power plant in the U.S. by December 31, 2014, we are permitted to claim a 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 fail to meet the start of construction deadline for such a project, then the 30% credit is reduced to 10%. In lieu of the 30% tax credit (if the project qualifies), we are permitted to claim a tax credit based on the power produced from a geothermal power plant. These production-based credits, which in 2013 were 2.3 cents per kWh, are 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% tax credit and the production-based tax credit. Under current tax rules, any unused tax credit has a one-year carry back and a twenty-year carry forward. If we claim the ITC, our "tax basis" in the plant that we can recover through depreciation must be reduced by half of the ITC. If we claim the PTC, there is no reduction in the tax basis for depreciation. Companies that placed qualifying renewable energy facilities in service during 2009, 2010 or 2011 or that began construction of qualifying renewable energy facilities during 2009, 2010 or 2011 and placed them in service by December 31, 2013, may choose to apply for a cash grant from the U.S. Treasury in an amount equal to the ITC. Likewise, the tax basis for depreciation will be reduced by 50% of the cash grant received. Under the ARRA, the U.S. Treasury is instructed to pay the cash grant within 60 days of the application or the date on which the qualifying facility is placed in service.

Ormat Systems received "Benefited Enterprise" status under Israel's Law for Encouragement of Capital Investments, 1959 (the Investment Law), with respect to two of its investment programs. As a Benefited Enterprise, Ormat Systems was exempt from Israeli income taxes with respect to income derived from the first benefited investment for a period of two years that started in 2004, and thereafter such income was subject to reduced Israeli income tax rates, which could not exceed 25% for an additional five years until 2010. Ormat Systems was also exempt from Israeli income taxes with respect to income derived from the second benefited investment for a period of two years that started in 2007. Thereafter, such income is subject to reduced Israeli income tax rates which cannot exceed 25% for an additional five years until 2013 (see also below). These benefits are subject to certain conditions, including among other things, that all transactions between Ormat Systems and its affiliates are done on an arm's- length basis, and that the management of Ormat Systems will be located in, and the control will be conducted from Israel during the entire period of the tax benefits. A change in control of Ormat Systems would need to be reported to the Israel Tax Authority in order for Ormat Systems to maintain the tax benefits. In January 2011, new legislation amending the Investment Law was enacted. Under the new legislation, a uniform rate of corporate tax will apply to all qualified income of certain industrial companies, as opposed to the previous law's incentives that are limited to income from a "Benefited Enterprise" during their benefits period. According to the amendment, the uniform tax rate applicable to the zone where the production facilities of Ormat Systems are located would be 15% in 2011 and 2012, 12.5% in 2013 and 16% in 2014 and thereafter. Under the transitory provisions of the new legislation, Ormat Systems had the option either to irrevocably comply with the new law while waiving benefits provided under the previous law or to continue to comply with the previous law during the transition period, with an option to move from the previous law to the new law at any stage. Ormat Systems decided to irrevocably comply with the new law starting in 2011.

In November 2012, new legislation amending the Investment Law was enacted. Under the new legislation, companies that had retained earnings as of December 31, 2011 from Benefited Enterprises would have elected by November 11, 2013 to pay a reduced corporate tax rate set forth in the new legislation on such undistributed income and distribute a dividend from such income without being required to pay additional corporate tax with respect to such income. Ormat Systems decided not to make such an election**.**

ITEM 7A. *QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK*

Information responding to Item 7A is included in Item 7 — "Management's Discussion and Analysis of Financial Condition and Results of Operations" of this annual report.

ITEM 8. ***FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA***

Index to Consolidated Financial Statements of Ormat Technologies, Inc. and Subsidiaries

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of Ormat Technologies, Inc.:

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of operations and comprehensive income (loss), equity, and cash flows present fairly, in all material respects, the financial position of Ormat Technologies, Inc. and its subsidiaries at December 31, 2014 and 2013, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2014 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2014, based on criteria established in *Internal Control — Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control over Financial Reporting appearing under Item 9A. Our responsibility is to express opinions on these financial statements and on the Company's internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

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

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

/s/ PricewaterhouseCoopers LLP

San Francisco, California

February 26, 2015

ORMAT TECHNOLOGIES, INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

	December 31,	
	2014	**2013**
	(Dollars in thousands)	
ASSETS		
Current assets:		
Cash and cash equivalents	$40,230	$57,354
Restricted cash and cash equivalents (all related to VIEs)	93,248	51,065
Receivables:		
Trade	48,609	95,365
Related entity	451	442
Other	10,141	11,049
Due from Parent	1,337	382
Inventories	16,930	22,289
Costs and estimated earnings in excess of billings on uncompleted contracts	27,793	21,217
Deferred income taxes	251	523
Prepaid expenses and other	34,884	29,654
Total current assets	273,874	289,340
Unconsolidated investments	—	7,076
Deposits and other	20,044	22,114
Deferred income taxes	—	891
Deferred charges	37,567	36,738
Property, plant and equipment, net ($1,339,342 and $1,381,083 related to VIEs, respectively)	1,437,637	1,452,336
Construction-in-process ($162,006 and $136,947 related to VIEs, respectively)	296,722	288,827
Deferred financing and lease costs, net	27,057	30,178
Intangible assets, net	28,655	31,933
Total assets	$2,121,556	$2,159,433
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable and accrued expenses	$88,276	$98,047
Deferred income taxes	974	—
Short term revolving credit lines with banks (full recourse)	20,300	—
Billings in excess of costs and estimated earnings on uncompleted contracts	24,724	7,903
Current portion of long-term debt:		
Limited and non-recourse (all related to VIEs):		
Senior secured notes	34,368	31,137
Other loans	17,995	20,377
Full recourse	19,116	28,875
Total current liabilities	205,753	186,339
Long-term debt, net of current portion:		
Limited and non-recourse (all related to VIEs):		
Senior secured notes	360,366	270,310

Other loans	264,625	311,078
Full recourse:		
Senior unsecured bonds (plus unamortized premium based upon 7% of $820)	250,289	250,596
Other loans	34,351	53,467
Revolving credit lines with banks (full recourse)	—	112,017
Unconsolidated investments	3,617	—
Liability associated with sale of tax benefits	39,021	60,985
Deferred lease income	60,560	63,496
Deferred income taxes	66,220	55,035
Liability for unrecognized tax benefits	7,511	4,950
Liabilities for severance pay	20,399	23,841
Asset retirement obligation	19,142	18,679
Other long-term liabilities	2,956	3,529
Total liabilities	1,334,810	1,414,322
Commitments and contingencies (Note 22)		
Equity:		
The Company's stockholders' equity:		
Common stock, par value $0.001 per share; 200,000,000 shares authorized; 45,537,162 and 45,460,653 shares issued and outstanding as of December 31, 2014 and 2013 , respectively	46	46
Additional paid-in capital	742,006	735,295
Retained earnings	41,539	(3,088)
Accumulated other comprehensive income	(8,668)	487
	774,923	732,740
Noncontrolling interest	11,823	12,371
Total equity	786,746	745,111
Total liabilities and equity	$2,121,556	$2,159,433

The accompanying notes are an integral part of the consolidated financial statements

ORMAT TECHNOLOGIES, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME (LOSS)

	Year Ended December 31,		
	2014	2013	2012
	(Dollars in thousands, except per share data)		
Revenues:			
Electricity	$382,301	$329,747	$314,894
Product	177,223	203,492	186,879
Total revenues	559,524	533,239	501,773
Cost of revenues:			
Electricity	246,630	232,874	237,415
Product	109,143	140,547	135,346
Total cost of revenues	355,773	373,421	372,761
Gross margin	203,751	159,818	129,012
Operating expenses:			
Research and development expenses	783	4,965	6,108
Selling and marketing expenses	15,425	24,613	15,718
General and administrative expenses	28,614	29,188	28,066
Impairment charge	—	—	236,377
Write-off of unsuccessful exploration activities	15,439	4,094	2,639
Operating income (loss)	143,490	96,958	(159,896)
Other income (expense):			
Interest income	312	1,332	1,201
Interest expense, net	(84,654)	(73,776)	(64,069)
Foreign currency translation and transaction gains (losses)	(5,839)	5,085	242
Income attributable to sale of tax benefits	24,143	19,945	10,127
Gain from sale of property, plant and equipment	7,628	—	—
Other non-operating income, net	756	1,592	590
Income (loss) from continuing operations, before income taxes and equity in income of investees	85,836	51,136	(211,805)
Income tax provision	(27,608)	(13,552)	(1,827)
Equity in losses of investees, net	(3,213)	(250)	(2,522)
Income (loss) from continuing operations	55,015	37,334	(216,154)
Discontinued operations:			
Income from discontinued operations (including gain on disposal of $0, $3,646 and $0, respectively)	—	5,311	4,811
Income tax provision	—	(614)	(1,264)
Total income from discontinued operations	—	4,697	3,547
Net income (loss)	55,015	42,031	(212,607)
Net loss attributable to noncontrolling interest	(833)	(793)	(414)
Net income (loss) attributable to the Company's stockholders	$54,182	$41,238	$(213,021)
Comprehensive income (loss):			
Net income (loss)	55,015	42,031	(212,607)

Other comprehensive income (loss), net of related taxes:			
Change in unrealized gains or losses in respect of the Company's share in derivatives instruments of unconsolidated investment	(6,302)	—	—
Loss in respect of derivative instruments designated for cash flow hedge	(902)	—	—
Amortization of unrealized gains in respect of derivative instruments designated for cash flow hedge	(141)	(164)	(190)
Change in unrealized gains or losses on marketable securities available-for-sale	—	—	246
Comprehensive income (loss)	47,670	41,867	(212,551)
Comprehensive loss attributable to noncontrolling interest	(833)	(793)	(414)
Comprehensive income (loss) attributable to the Company's stockholders	$46,837	$41,074	$(212,965)
Earnings (loss) per share attributable to the Company's stockholders:			
Basic:			
Income (loss) from continuing operations	$1.19	$0.81	$(4.77)
Discontinued operations	—	0.10	0.08
Net income (loss)	$1.19	$0.91	$(4.69)
Diluted:			
Income (loss) from continuing operations	$1.18	$0.81	$(4.77)
Discontinued operations	—	0.10	0.08
Net income (loss)	$1.18	$0.91	$(4.69)
Weighted average number of shares used in computation of earnings per share attributable to the Company's stockholders:			
Basic	45,508	45,440	45,431
Diluted	45,859	45,475	45,431
Dividend per share declared	$0.21	$0.08	$0.08

The accompanying notes are an integral part of the consolidated financial statements.

ORMAT TECHNOLOGIES, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF EQUITY

The Company's Stockholders' Equity		
	Retained	Accumulated
Additional	Earnings	Other