ORMAT TECHNOLOGIES, INC.
Form 10-K
February 28, 2014

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, 2013

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, 2013, 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 $389,817,905 based on the closing price as reported on the New York Stock Exchange.

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, 2014, the number of outstanding shares of common stock, par value $0.001 per share was 45,460,653.

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, 2013.

ORMAT TECHNOLOGIES, INC.

FORM 10-K FOR THE YEAR ENDED DECEMBER 31, 2013

TABLE OF CONTENTS

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
DISNORTE	Empresa Distribudora de Electricidad del Norte (a Nicaragua distribution company)
DISSUR	Empresa Distribudora de Electricidad del Sur (a Nicaragua distribution company)
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.

1

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 power 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
Parent	Ormat Industries Ltd.
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
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

4

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, 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;

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 such as the threat or occurrence of 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 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. We have expanded our activities in the Electricity Segment to include the ownership and operation of power plants that produce electricity generated by Solar PV systems that we do not manufacture;

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 chart below sets forth a breakdown of our revenues for each of the years ended December 31, 2013 and 2012: 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".

Segment Contribution to Revenues

7

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. 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 the recent years, we have expanded our activity to the Solar PV industry. We are monitoring market drivers with to the potential for developing Solar PV power plants in locations where we can offer competitively priced power generation**.** We recently completed most of the work on the Solar PV project, which is located near our Heber complex in California and we are awaiting the completion of the interconnection to the grid by the utility. We are considering the option of selling the project prior to completion.

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, 2014. 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:

Power Plant	**Location**	**Ownership**[1]		**Generating Capacity in MW**[2]
Domestic				
Geothermal				
Brady Complex[3]	Nevada	100	%	18.0
Heber Complex[4]	California	100	%	92.0
Jersey Valley[5]	Nevada	100	%	12.0
Mammoth Complex	California	100	%	29.0
McGinness Hills	Nevada	100	%	38.0
North Brawley[6]	California	100	%	27.0
Ormesa Complex	California	100	%	54.0
Puna Complex	Hawaii	100	%	38.0
Steamboat Complex[3]	Nevada	100	%	78.0
Tuscarora	Nevada	100	%	18.0
Don A. Campbell[7]	Nevada	100	%	16.0
REG				
OREG 1	North and South Dakota	100	%	22.0
OREG 2	Montana, North Dakota and Minnesota	100	%	22.0
OREG 3	Minnesota	100	%	5.5
OREG 4[8]	Colorado	100	%	3.5
Total for domestic power plants				**473.0**
Foreign				
Geothermal				
Amatitlan	Guatemala	100	%	20.0
Olkaria III Complex	Kenya	100	%	110.0
Zunil[9]	Guatemala	97	%	23.0
Total for foreign power plants				**153.0**
Total for all power plants				**626.0**

(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 revenues are calculated based on 24 MW capacity unrelated to the actual performance of the reservoir. This column represents our net ownership in such generating capacity.

In any given year, the actual power generation of a particular power plant may differ from that power plant's generating capacity due to variations in ambient temperature, the availability of the resource, and operational issues affecting performance during that year. The Capacity Factor of our geothermal operating power plants in 2013 excluding the Heber complex, Mammoth complex and Jersey Valley power plant, where we intentionally conducted work that resulted in lower generation than the respective complex' or plant's generating capacity, was approximately 90%. The Capacity Factor of our REG power plants in 2013 was approximately 82%.

(3) 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.

(4) The Heber complex generating capacity is based on our expectations for the upgrade project for Heber 1 which is expected to be completed in 2014. That work will require a total plant outage projected to occur during the first six months of 2014 See "Description of Our Power Plants" below.

(5) Well field and power plant enhancement work was conducted in Jersey Valley through 2013 and we expect to meet this generating capacity during 2014.

(6) Following recent developments, detailed under "Description of Our Power Plants" below, we have decided to operate the North Brawley power plant at its current capacity level of approximately 27 MW.

(7) The Don A. Campbell power plant commenced operation on December 6, 2013

(8) 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.

(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.

All of the revenues that we currently derive from the sale of electricity are pursuant to long-term PPAs. Approximately 44.0% of our total revenues in the year ended December 31, 2013 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 40 MW in generating capacity from geothermal power plants in the United States that we fully released for construction and are in different stages of construction. In addition, we have several projects that are either under initial stages of construction or under different stages of development with an aggregate capacity of up to approximately 172 MW.

We have a substantial land position across 37 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 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. 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 Ltd. (also referred to in this annual report as the "Parent", "Ormat Industries", "the parent company", or "our parent"). 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. Ormat Industries owns approximately 60% of our outstanding common stock.

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 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.

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 77 U.S. patents that are still in force (and have approximately 33 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, disposal of non-condensable gases present in geothermal fluids, power plants for very high pressure geothermal resources, and 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 17 years. The loss of any single patent would not have a material effect on our business or results of operations.

Research and Development

We are conducting research and development activities intended to improve plant performance, reduce costs, and increase the breadth of product offerings. The primary focus of our research and development efforts includes continued improvements to our condensing equipment with improved performance and lower 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 Desert Peak 2 and Brady power plants 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 product offerings 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 are opportunities for development in other states such as Alaska, Arizona, New Mexico, Washington and Oregon due to the potential of geothermal resources.

In a report issued in April 2013, the GEA identified 175 confirmed and unconfirmed geothermal projects under various phases of consideration or development in 13 U.S. states. These projects have between 5,150 MW and 5,523 MW geothermal resource potential.

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, 23 states have enacted RPS, 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 expect that the additional demand for renewable energy from utilities in states with RPS will outpace a possible reduction in general demand for energy (if any) due to the effect of general economic conditions. We see this increased demand and, in particular, the impact of the RPS legislation and the increase in California’s RPS to 33% by 2020, 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 19.96% of their 2012 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 a new market of potential off-takers for us. These utilities do not have interim targets.

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 19, 2013, the CARB released the results of its fifth auction, reporting that the vintage 2013 auction clearing price was $11.48 per allowance and the 2016 vintage auction clearing price was $11.10 per allowance. All of the available 2013 and 2016 vintage allowances were sold.

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 2012, not less than 15% of electricity sold to Nevada retail customers must have been met with renewable energy resources and credits, and that not less than 5% of that amount must be met with solar resources. According to NV Energy's RPS Annual Report, in 2012, Nevada Power exceeded both the 2012 RPS requirement and the 2012 solar RPS requirement, achieving 9.7% and 19.3%, respectively. Sierra exceeded both the 2012 RPS requirement and the 2012 solar RPS requirement, with 29.2% and 14.4% respectively. Nevada's RPS compliance requirement has increased to 18% for 2013 and 2014.

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 2013 filing made with the Hawaii PUC, in 2012, Hawaiian Electric Company and its subsidiaries exceeded the 2012 RPS requirement, achieving a consolidated RPS of 28.7% 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 2012 renewable generation percentage for the Hawaiian Electric Companies was 13.9%.

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 and NA2050, other states have also established the Midwestern Regional Greenhouse Gas Reduction Accord, the Western Climate Initiative. 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, an initiative that will help support continued renewable energy developments in the U.S.

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, 2013, 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 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% tax credit (if a geothermal 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. For a new solar plant in the U.S. that is placed in service by December 31, 2016, 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. 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.

For certain geothermal and solar projects, we can elect to receive a cash payment from the U.S. Treasury Department in lieu of these tax credits. To qualify, the project must have been under construction by December 31, 2011, the project company must have filed a preliminary application by September 30, 2012, and the project must be placed in service by December 31, 2016. A final application must be filed shortly after placing the project into service. No portion of the project may be owned by certain disqualified persons (or indirectly through a pass-through entity by such a person). The cash payment would be 30% of certain eligible costs, with two exceptions. First, for geothermal projects placed in service after December 31, 2013 and before January 1, 2017, the payment is reduced to 10%. Second, in all cases, the payments are subject to reduction for sequestration under the Balanced Budget and Emergency Deficit Control Act of 1985, as amended. The sequestration reduction for these payments for the 2014 fiscal year is 7.2%.

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 we claim in the future 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 GEA, there are 11,766 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. In November 2013, the United Nations Climate Change Conference was held in Warsaw, Poland. The conference encompassed the 19th Conference of the Parties to the United Nations Framework Convention on Climate Change and the ninth meeting of the Parties to the Kyoto Protocol. Countries decided to initiate or intensify domestic preparation for their intended national contributions towards an agreement to be reached in 2015, which will come into effect in 2020. Parties are required to submit clear and transparent plans to curb greenhouse gas emissions by the first quarter of 2015. The next Conference of the Parties is scheduled to take place in Lima, Peru, at the end of 2014.

In September 2014, the United Nations will hold a Climate Summit in New York City aiming to catalyze action by governments, business, finance, industry, and civil society toward a low-carbon economy.

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 2003, 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, has been instructed to 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 2034.

In **Chile**, where we have six 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. In 2013, Chile set a new target doubling the nation’s renewable energy aimed to produce 20% of the country’s power by renewable sources by 2025, replacing the previous requirement.

Oceania

In **New Zealand**, where we and our parent company 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 and East Africa

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 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 tariffs which are also based on the expected size of the power plant and quality of the resource. 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, which is intended to be achieved mainly through prevention of deforestation and accelerated renewable energy development.

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.

The **Rwanda** government has commenced drilling as part of the country’s efforts to boost electricity capacity through exploration of renewable energy sources. The governments of **Djibouti, Ethiopia, Eretria, Tanzania, Uganda and Zambia** are also exploring ways to develop geothermal in their countries.

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 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. Key members of our senior management team have worked in the power industry for most of their careers and average over 25 years of industry experience.

Technological Innovation. We have 77 U.S. patents in force (and have approximately 33 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 and which meet our investment criteria;

- *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 that meet our investment criteria;

- *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;

- *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 11, 2014, our Board of Directors appointed Mr. Isaac Angel as CEO. Mr. Angel will join Ormat on April 1, 2014 and assume the CEO position effective July 1, 2014. He will succeed Mrs. Yehudit (Dita) Bronicki, who announced her retirement in November 2013. Mrs. Bronicki will continue to serve as a Director of Ormat in a non-executive capacity. We further announced that Mr. Gillon Beck will step down from his position of chairman of the board of directors of the company effective June 30, 2014 and the board of directors has elected and appointed Mr. Yoram Bronicki as the succeeding chairman, with such appointment being also effective June 30, 2014. Mr. Beck will continue to serve as a director of the company after he steps down from his position as chairman. Upon assuming the position of the chairman of the board Mr. Yoram Bronicki will relinquish his position as president and chief operating officer of the company.

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 almost three months ahead of schedule. 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 million comprising Tranche III of the previously announced $310 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 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 our wholly owned subsidiary 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.

On January 6, 2014, we announced that we completed the construction of the Don A. Campbell geothermal power plant in Mineral County, Nevada. The plant is currently producing at full generating capacity of 16 MW and performing as expected. 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 SCPPA. SCPPA resells the power from the Don A. Campbell geothermal power plant to the LADWP and Burbank Water and Power through NV Energy Inc.'s transmission system.

On December 2, 2013, we announced that we completed the acquisition of Geotérmica Platanares, a late-stage development 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 megawatt with ENEE, the national utility of Honduras, under a BOT structure for approximately 15 years. We plan to begin phased development at the project and start drilling wells in the first half of 2014. 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 with an expectation to reach commercial operation in about three years.

On November 14, 2013, we announced that a key milestone was reached in the 30 MW (MW) expansion of the McGinness Hills geothermal power plant complex located in Lander County, Nevada. NV Energy and Ormat signed an amendment to the existing McGinness Hills PPA allowing us to sell 63.7 MW (net average annual capacity) from the complex. Under the amendment, a new energy rate of $85.58/MWh with a one percent annual escalator will be set for the entire complex once McGinness Hill Phase II enters commercial operation, expected in mid-2015. The amendment was approved by the Nevada PUC.

On October 8, 2013, we announced that we entered into an agreement for the development of the Hu'u Dompu greenfield geothermal project in Indonesia. Subject to availability of sufficient geothermal resource, we will develop the project through Pacific Geo Energy (PAGE), a project company, in which Ormat will hold 90% and the remaining 10% will be held by the current owner of the company. The Hu'u Dompu project is located in West Nusa Tenggara Province on Indonesia's Sumbawa Island, and may be developed for up to 60 MW in three phases over the next six years.

On September 26, 2013, we entered into a Joint Development Agreement with eBay Inc. for the development of a 5 MW REG power plant to be constructed in Utah. The Joint Development Agreement allows eBay and us to begin preliminary development work to supply cleaner electricity to eBay's new Salt Lake City-based data center while entering into negotiations for a 20-year term contract.

On September 6, 2013, we announced that we entered into a 10-year PPA with SCPPA to deliver electricity from our Heber 1 geothermal power plant at the Heber complex in Imperial Valley, California beginning December 16, 2015. The current PPA with Southern California Edison will expire December 15, 2015. With an expected net generating capacity of 46 MW, we expect to sell the power to SCPPA at an average price of approximately $85.62 per MWh over the lifetime of the agreement. The new pricing is expected to increase Heber 1 revenues in 2016 by more than $7.0 million compared to our 2013 revenues. SCPPA members that will receive power from Heber 1 are LADWP and IID.

On July 15, 2013, we converted $263.0 million in principal amount outstanding under our debt facility with OPIC from a floating interest rate to a fixed interest rate. The conversion applies to both tranches of the facility, which is being used to finance the Olkaria III complex in Naivasha, Kenya. The average fixed interest rate for Tranche I, which has an outstanding balance of $82.6 million and matures on December 15, 2030 and Tranche II, which has an outstanding balance of $180.0 million and matures on June 15, 2030, is 6.31%.

On June 3, 2013, we announced that our wholly owned subsidiary, Ormat Holding Corp., sold its stake in Momotombo Power Company (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 arrangement with the Nicaraguan owner. This amount represents a prepayment of the expected EBITDA of the plant through the scheduled expiration of the contract. As a result of the sale, we recorded an after-tax gain of approximately $3.6 million in the second quarter of 2013.

On May 2, 2013, we announced that we reached commercial operation of Plant 2 in the Olkaria III complex in Naivasha, Kenya, increasing our then total worldwide generating capacity by 36 MW. The power generated in the Olkaria III complex is sold under a 20-year PPA with KPLC.

On April 4, 2013, Sarulla Operations Ltd. (SOL) signed amendments to the Joint Operating Contract (JOC) and the Energy Sales Contract (ESC) for the 330 MW Sarulla geothermal power project in Tapanuli Utara, North Sumatra in Indonesia. We designed the plant and will supply our OEC to the power plant, as a result of which we expect to recognize revenues of approximately $254.0 million related to the equipment sales over the construction period. In addition, through our wholly owned subsidiary, we hold a 12.75% in a consortium which owns and operates the Sarulla project. Other members of the consortium include Medco Energi Internasional Tbk (Medco); Itochu Corporation (Itochu); and Kyushu Electric Power Co. Inc (Kyushu).

The consortium has started preliminary testing and development activities at the site, and some basic infrastructure work. The third party contracts for EPC and drilling as well as the supply contract for equipment with us have all been signed. Construction is expected to begin after the consortium obtains financing, which is expected to occur in the first half of 2014, but a limited notice to proceed has already been issued by the consortium members to the EPC contractor. The first phase is scheduled to commence operation in 2016, with the remaining two phases scheduled to be completed in stages within 18 months thereafter.

The project is expected to obtain construction and term loans under a non-recourse or limited-recourse financing package of direct loans from JBIC and ADB, as well as loans to be provided by five commercial banks (the MLAs). The MLAs are expected to be backed by political risk guarantees from JBIC.

On April 1, 2013, we began to sell geothermal power from the G3 plant in the Mammoth Complex in California to PG&E under a new 20 year PPA for up to 14 MW. On March 15, 2013, we finalized the agreement with Southern California Edison, by which the G1 and G3 SO#4 PPAs were terminated and, in connection therewith, we paid a termination fee of approximately $9.0 million in the first quarter of 2013. Under the agreement, we will continue to sell power from G2, the third plant of the Mammoth complex, under its existing PPA with Southern California

Edison, with the term of the contract extended by an additional six years until early 2027.

On January 24, 2013, Ormat Nevada, our wholly owned subsidiary, and JPM entered into a tax equity partnership transaction involving certain geothermal power plants in California and Nevada. As part of the transaction, Ormat Nevada transferred the plants into ORTP, a new wholly owned subsidiary, and sold an interest in ORTP to JPM. In connection with the closing, JPM paid to Ormat Nevada approximately $35.7 million and will make additional payments to Ormat Nevada based on the value of PTCs generated by the portfolio over time that are expected to be made until December 31, 2016 and up to a maximum amount of $11.0 million.

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 below 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.

- 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.
- 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, 2013, in the Electricity Segment we focused on the construction of the Don A. Campbell power plant (formerly Wild Rose), Olkaria III Plant 2 and Plant 3 geothermal projects in order to meet the respective completion deadlines. During the year ended December 31, 2013, 2012 and 2011 two sites (Olkaria III plant 3 and McGinness Hills phase 2), no sites and one site (Olkaria III Plant 2) moved to construction, respectively.

We discontinued exploration activities at four sites in Idaho, Nevada, Oregon and Utah during the year ended December 31, 2013 and at five sites in Nevada during the year ended December 31, 2012. Those sites were Magic Reservoir, Wildhorse (Mustang), Mahogony and Drum Mountain in 2013, and Leach Hot springs, Hyder Hot Springs, Seven Devil, Smith Creek and Walker River in 2012. After conducting exploratory studies 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. No exploration activities were discontinued in 2011 (see “Write-off of Unsuccessful Exploration Activities” under Item 7 — “Management Discussion and Analysis of Financial Condition and Results of Operations”).

Three new sites were added to our exploration and development activities in the year ended December 31, 2013, compared with five sites in the year ended December 31, 2012 and with thirteen sites in the year ended December 31, 2011.

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, lease financing, parent company loans, and 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. However, insurance policy for the Amatitlan Geothermal Project in Guatemala was discontinued following the financing of the project in 2009 due to our reduced equity exposure.

Description of Our Leases and Lands

We have domestic leases on approximately 369,330 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;

- 14% are leases with private landowners and/or leaseholders;

- 11% are leases with various states, none of which is currently material; and

- 3% are owned by us.

Each of the leases within each of the categories has standard terms and requirements, as summarized below. Internationally, our land position includes approximately 413,430 acres, most of which are geothermal exploration licenses in six 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 of waste brine and other waste products 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 have 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 can 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. As of the date of this report we have received an extension for one of the six concessions. We are considering submitting applications for exploitation licenses that would last longer than current exploration licenses for selected concessions where the results of previous exploration support conducting further surveys.

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 8 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 274 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.
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 (formerly Wild Rose) Project

Location	Mineral County, Nevada
Generating Capacity	16 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 first 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 expect to receive from the U.S. Treasury.

Heber Complex

Location	Heber, Imperial County, California
Generating Capacity	92 MW

Number of Power Plants	Five (Heber 1, Heber 2, Heber South, Gould 1 and Gould 2).
Technology	The Heber 1 plant is a dual flash system with a binary bottoming unit called Gould-1 and the Heber 2 group is comprised of the Heber 2, Gould 2 and Heber South plants which all utilize binary systems. The complex uses a water cooled system.
Subsurface Improvements	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 348 degrees Fahrenheit. The resource supplying the pumped Heber 2 wells averages 318 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	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 began an upgrade project for the Heber 1 area which is expected to make better use of the available resource and includes drilling new wells, decommissioning old wells and replacing the surface equipment.

At the end of this process, we expect the capacity of the complex to reach 92MW.

The work on the surface equipment will be done in the first half of 2014 and will require a total plant outage. However, we expect to realize the benefits of this upgrade in future years.

Jersey Valley Power Plant

Location	Pershing County, Nevada
Generating Capacity	12 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 326 degrees Fahrenheit.
Resource Cooling	We expect three degree Fahrenheit per year.
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	During 2013, we made progress in increasing the injection capacity of the Jersey Valley power plant, which has been limiting generation in its early years. We expect the results of the work, which was completed in January 2014, to allow us to operate at a capacity of 12MW once completed.

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". We purchased land at Mammoth that was owned by a third party. This purchase reduced royalty expenses for the Mammoth complex.
Access to Property	Direct access to public roads from the leased property and access across the

leased property are provided under surface rights granted pursuant to the leases.

Resource Information	The average resource temperature is 339 degrees Fahrenheit.
	The Casa Diablo/Basalt Canyon geothermal field at Mammoth lies on the southwest edge of the resurgent dome within the Long Valley Caldera. It is believed that the present heat source for the geothermal system is an active magma body underlying the Mammoth Mountain to the northwest of the field. Geothermal waters heated by the magma flow from a deep source (greater than 3,500 feet) along faults and fracture zones from northwest to southeast east into the field area.
	The produced fluid has no scaling potential.
Resource Cooling	In the last year the temperature was 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. The refurbishment work required shutting down the G1 plant for most of 2013 but since its completion the complex is generating power at the expected levels. In addition, a refurbishment program for G-3 is currently in process with an expected completion in 2015.

<u>McGinness Hills Power Plant</u>

Location	Lander County, Nevada
Generating Capacity	38 MW
Number of Power Plants	One
Technology	The McGinness Hills power plant utilizes an air cooled binary system.

Subsurface Improvements	Five production wells and three injection wells are connected to the power plant.
Material Equipment	Two air cooled OEC units with the Balance of Plant Equipment.
Age	The power plant commenced commercial operation on July 1, 2012,
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 plant 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.
Supplemental Information	Succesfull field development and equipment design implemented in the McGinness Hills enabled us to increase its generating capacity to 38MW.

North Brawley Power Plant

Location	Imperial County, California
Generating Capacity	27 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. Instead, it has been operating at capacities between 20 MW and 33 MW. This generation level has been achieved following significant additional capital expenditures and a higher than anticipated operating costs. 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 27 MW and refrain from additional capital investment to expand the capacity until further geological analysis is completed and/or a higher energy rate will be secured. As noted above, during the fourth quarter of 2012 we recognized an impairment charge of $229.1 million for this plant.

<u>OREG 1 Power Plant</u>

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.

<u>OREG 2 Power Plant</u>

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.

<u>OREG 3 Power Plant</u>

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.

<u>OREG 4 Power Plant</u>

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.

<u>Ormesa Complex</u>

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 305 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.

Puna Complex

Location	Puna district, Big Island, Hawaii
Generating Capacity	38 MW
Number of Power Plants	Two
Technology	The Puna plants utilize our geothermal combined cycle and binary systems. The plants use an air cooled system.
Subsurface Improvements	Five production wells and four injection wells connected to the plants through a gathering system. We drilled a sixth production well, which we have not connected to the site yet.
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	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:

- 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.

- 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 are currently in discussions with HELCO to convert the avoided costs 25 MW contract to a fixed price contract.

<u>Steamboat Complex</u>

Location	Steamboat, Washoe County, Nevada
Generating Capacity	78 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.
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. We are looking at options to moderate the temperature decline.
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.

<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 342 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 526 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.
Supplemental Information	During 2013, we drilled a new well at the same location of an old plugged production well, by using new technology and larger casing diameter, which enabled us to increase the generating capacity back to 20 MW. The power plant was registered by the United Nations Framework Convention on Climate Change as a Clean Development Mechanism. It is expected to offset emissions of approximately 83,000 tons of CO_2 per year.

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.

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.
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
Financing	Senior secured project loan from IFC and CDC that was repaid in full in November 2011.
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 13 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.

According to the PPA amendment, payments for the Zunil plant will be made as follows:

- Capacity payment:

  - o Until 2019, the capacity payment will be calculated based on 24 MW capacity regardless of the actual performance of the power plant.

- From 2019 and onwards, the capacity payment will be based on actual delivered capacity and the capacity rate will be reduced.

• Energy payment:

- 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.

- 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 domestic 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 California and Nevada with an expected total generating capacity of 40MW that were released and are in different stages of construction.

Heber Solar PV Project (U.S.)

Location	Imperial County, California
Projected Generating Capacity	10 MW (24,500 MWh per year)
Projected Technology	Solar PV
Condition	Completed most of the work and awaiting the completion of the interconnction facilities.
Land	The Heber Solar area is comprised of land that we own.
Access to Property	Direct access to public roads from the leased property and access across the leased property.
Power Purchaser	IID
PPA Expiration Date	20 years after date of COD.
Financing	Corporate funds.
Projected Operation	2014
Supplemental Information	We expect interconnection work to be completed by the end of the first quarter of 2014. We are considering the option of selling the project prior to completion.

McGinness Hills Phase 2 (U.S.)

Location	Lander County, Nevada
Projected Generating Capacity	30 MW

Projected Technology	The McGinness Hills Phase 2 power plant will utilize a binary system.
Material Equipment	Power plant equipment and the Balance of Plant.
Condition	Field development is in process.
Subsurface Improvement	We completed the drilling of the first production well.

Land and Mineral Rights	The McGinness Hills phase 2 area is comprised of private and BLM leases.
	The leases of the McGinness Hills area are production of the McGinness Hills plant, 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 expected average temperature of the resource is approximately 335 degrees Fahrenheit.
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.
Financing	Corporate funds. We expect to finance this project under the OFC 2 Senior Secured Notes.
Projected Operation	Mid-2015

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

Carson Lake Project (U.S.)

Location	Churchill County, Nevada
Projected Generating Capacity	20 MW
Projected Technology	The Carson Lake power plant will utilize a binary system.
Condition	Initial stage of construction; 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.

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, Honduras, and Indonesia. 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 122 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 2014.

Crump Geyser Project (U.S.)

In October 2010, we and AER (formerly NGP) agreed to jointly develop, construct, own and operate one or more geothermal power plants in the Crump Geyser Area located in Lake County, Oregon. All activities will be carried out through CGC, a limited liability company that is owned equally by our wholly owned subsidiary, Ormat Nevada, and AER.

We will be the EPC contractor for the project, which is expected to be up to 20MW and be placed in service gradually. The project will utilize our proprietary generating equipment and other Balance of Plant equipment. We will also be the Operator and provide operating and maintenance services to CGC.

According to the original agreement, we have to meet certain conditions by June 30, 2014.

e-Bay REG Project (U.S.)

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

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 Power Purchase Agreement 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. We plan to begin phased development of the project and start drilling wells early this year. 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 late 2016 or the beginning of 2017.

Sarulla Project (Indonesia)

We are a member of a consortium which is in the process of developing the Sarulla geothermal power project in Indonesia, of approximately 330 MW. We own 12.75% of the project directly through our 100% owned special purpose entity and through 12.75% ownership in an Indonesian special purpose entity that will develop and operate the project.

The Sarulla project is located in Tapanuli Utara, North Sumatra, Indonesia and will be owned and operated by the consortium members under the framework of a JOC and ESC, amendments to both of which were signed on April 4, 2013. 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. As a supplier, we expect to recognize revenues of $254 million related to the equipment sale over the construction period. The supply contract was signed in October 2013.

The consortium has started preliminary testing and development activities at the site and signed an EPC and a drilling contract with an unrelated third party. The project will be constructed in three phases of 110 MW each, utilizing both steam and brine extracted from the geothermal field to increase the power plant’s efficiency. Construction is expected to begin after the consortium obtains financing, which is expected to occur in the first half of 2014, but a limited notice to proceed has already been issued by the consortium members to the EPC contractor. The first phase is scheduled to commence operations in 2016, and the remaining two phases are scheduled to be completed in stages within 18 months thereafter.

The project is expected to obtain construction and term loans under a limited or non-recourse financing package of direct loans from the Japan Bank for International Cooperation (JBIC) and the Asian Development Bank (which obtained board approval in December 2013), as well as loans to be provided by five commercial banks (the MLAs). The MLAs are expected to be backed by political risk guarantees from JBIC.

Wister Project (U.S.)

We plan to develop the Wister project on private leases located in Imperial County, California. We expect the first phase of the project to be 30 MW. Exploration activity under this program has started.

Since it became clear that Wister will not be able to meet the PPA milestones and the transmission line (which is not under our responsibility) will not be ready on time, the PPA was recently terminated with no penalty.

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.	Argenta	Under exploration studies;
2.	Aqua Quieta	Completed exploration studies;
3.	Baltazar	Completed exploration studies;
4.	Beowawe	Under exploration studies;
5.	Dixie Hope	Under exploratory drilling (includes Dixie Meadows- Comstock, which we presented as a separate prospect in the past);
6.	Don A. Campbell expansion	Under resevoir evaluation studies;
7.	Edwards Creek	Under exploratory drilling;
8.	Hycroft	Under exploration studies;

9. Tungsten Mountain	Under exploratory drilling;
10. Tuscarora	Completed exploration studies;
11. Trinity	Under exploration studies; and
12. South Jersey	Lease acquired but no further action has yet been taken.

California [2]

1. East and North Brawley	Deep resource lease acquired but no further action has yet been taken; and
2. Rhyolite Plateau	Lease acquired but no further action has yet been taken.

Hawaii [3]

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

Oregon [3]

1.	Glass Buttes — Midnight Point	Completed exploration studies; awaiting permits to start exploratory drilling (includes Mahogany, which we presented as a separate prospect in the past);
2.	Newberry — Twilight	Started exploratory drilling; and
3.	Lakeview/ Goose Lake	Completed exploration studies.

Alaska [1]

1.	Mount Spurr	Performed exploration drilling at the site.

Utah [1]

1.	Whirlwind Valley	Under exploration studies.

New Mexico [1]

1.	Rincon	Under exploration studies.

Guatemala [2]

1.	Amatitlan Phase II	Completed exploration studies; expected to start exploratory drilling.
2.	Tecumburu	Under exploration studies.

New Zealand [1]

1.	Tikitere	Signed BOT agreement; submitted request to obtain permits for exploratory drilling.

Indonesia [1]

1.	Huu Dompu	Land rights obtained but no further action has yet been taken;

In addition, we have exploration concessions for geothermal resources of approximately 336,131 acres in the following prospects:

Chile [6]

1.	San Pablo	Under exploration studies;
2.	Aroma	Under exploration studies;
3.	Mariman	Under exploration studies; we have recently submitted an application for exploitation license;
4.	Quinohuen	Under exploration studies; we have recently submitted an application for exploitation license;
5.	San Jose II	Under exploration studies; and
6.	Sollipulli	Under exploration studies; we have recently submitted an application for exploitation license.

We also have an option to enter into geothermal leases covering more than 264,000 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 [5]

1.	Foley Hot Springs	Started exploration studies.
2.	Silver Lake	Started exploration studies.
3.	Summer Lake	Started exploration studies.
4.	Winema	Started exploration studies; and
5.	Warm Springs Tribe	Started exploration studies.

Others

GDC (Kenya). A joint venture in which we own 51% recently won an award to negotiate an Energy Conversion agreement for a 30MW project in Kenya as part of GDC's activity to accelerate the development of geothermal power in the country. GDC is a Kenyan company owned by the Kenyan Government.

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 $165.0 million as of February 26, 2014, which includes revenues for the period between January 1, 2014 and February 26, 2014, compared to $262.2 million as of February 15, 2013, which included revenues for the period between January 1, 2013 and February 15, 2013.

The following is a breakdown of the Product Segment backlog as of February 26, 2014 (in millions):

Expected Completion of the Contract	**Sales Expected to be Recognized in 2014**					**Sales Expected to be Recognized in the years following 2014**	**Expected Until End of Contract**
	Q1	**Q2**	**Q3**	**Q4**	**Total**		

Geothermal	2014	$49.0	$44.0	$28.0	$17.0	$138.0	$ -	$ 138.0
Recovered Energy	2014	-	-	-	-	-	-	-
Remote Power Units	2014	-	2.0	8.0	2.0	12.0	-	12.0
Other	2017	1.0	2.0	2.0	2.0	7.0	8.0	15.0
Total		**$50.0**	**$48.0**	**$38.0**	**$21.0**	**$157.0**	**$ 8.0**	**$ 165.0**

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 Heavy Industries, LTD, Fuji Electric Co., Ltd. and Toshiba of Japan, GE/Nuovo Pignone brand and Ansaldo Energia of Italy, and Alstom S.A. of France.

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 Heavy Industries, LTD (which recently acquired Turboden), or systems integrators such as Turbine Air Systems and Geothermal Development Associates of the U.S. While we believe that we have a distinct competitive advantage based on our accumulated experience and current worldwide share of installed binary generation capacity (which is approximately 90%), an increase in competition, which we are currently experiencing, has started to impact our ability to secure new purchase orders from potential customers. The increased competition may also lead to a reduction in the prices that we are able to charge for our binary equipment, which in turn may impact our profitability.

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

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

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

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, 2013 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 14.2%, 17.6%, 9.2% and 1.7% of revenues, respectively, for the year ended December 31, 2013. Based on publicly available information, as of December 31, 2013, 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)	A3 (possible upgrade)
HELCO	BBB- (stable outlook)	Baa1(under review)
Sierra Pacific Power Company	BBB+ (stable outlook)	Baa2 (under review)
Nevada Power Company	BBB+ (stable outlook)	Baa2 (under review)
SCPPA	A- (Negative outlook)	Aa3 (stable outlook)
Pacific, Gas and Electric	BBB- (Negative outlook)	Aa3 (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, 2013, we employed 1,123 employees, of which 481 were located in the United States, 531 were located in Israel and 111 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, 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 the Overseas Private Investment Corporation (an agency of the U.S. government), or MIGA (a member of the World Bank Group), and 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. We have obtained such insurance for all of our foreign power plants currently in operation. However, the policy for the Amatitlan Geothermal Project in Guatemala was terminated following the financing of the project in 2009 due to our reduced equity exposure. 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.

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 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 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 this final rule 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. However, the rule protects a Qualifying Facility’s rights under any contract or obligation for the sale of energy in effect or pending approval before the appropriate state regulatory authority or non-regulated electric utility on August 8, 2005. Until that contract expires, is terminated or is materially modified, the Qualifying Facility 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, financial, and organizational 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. 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. 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 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 would 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 of geothermal facilities. 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 61.8% of our total revenues for the year ended December 31, 2013 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 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 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. 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. 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. Serious seismic disturbances 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, 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.

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.

Unfavorable meteorological conditions may have a negative effect on electricity production at our Solar PV projects and, therefore, the revenue from such projects may be substantially below our expectations.

The electricity that we expect to produce and the revenue that we expect to generate by our Solar PV power plants are highly dependent on suitable solar conditions and associated weather conditions, which are beyond our control. It is possible that the solar energy at our Solar PV plants will be lower than expected, which would result in an unexpected reduction in energy production and performance and decreased revenues at our Solar PV 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. We entered the solar energy sector of the renewable energy industry and have signed a PPA with IID for a 10 MW Solar PV project in Imperial Valley, California. 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. Our lack of experience in the Solar PV sector may also affect our ability to successfully develop, construct, finance, and operate the Solar PV power projects.

Currently, we have power plants 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 in the Solar PV sector where we will use equipment manufactured 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.

The aftermath of the recent global recession and its attendant credit constraints could adversely affect us.

We may continue to experience lower levels of worldwide demand for energy and face tighter credit markets, as the world economy continues to recover from the disruption in the global credit markets, failures or material business deterioration of investment banks, commercial banks, and other financial institutions, concerns over the European Union debt and currency crisis and significant reductions in asset values across businesses, households and individuals that led to the recent global recession. These conditions may adversely affect both our Electricity and Product Segments. Among other things, we might face:

- potential adverse impacts on our ability to negotiate waivers or modifications of the terms of existing financing arrangements with existing lenders if and when that might be necessary;

- potential declines in revenues in our Product Segment due to reduced or postponed orders or other factors caused by economic challenges faced by our customers and prospective customers; and

- potential adverse impacts on our customers' ability to pay, when due, amounts payable to us and related increases in our cost of capital associated with any increased working capital or borrowing needs we may have if this occurs, or to collect amounts payable to us in full (or at all) if any of our customers fail or seek protection under applicable bankruptcy or insolvency laws.

Any of these things could materially adversely affect our business, financial condition, operating results, and cash flow.

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. As of December 31, 2013, we had approximately $1,077.9 million of total consolidated indebtedness, of which approximately $632.9 million represented non-recourse and limited recourse debt held by our subsidiaries. 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, parent company loans 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 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, that generated aggregate revenues in the amount of $224.6 million for the year ended December 31, 2013, which represented 42.1% of our total revenues for such year. 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 net 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 net revenue is attributed to revenues derived from power purchasers under the relevant PPAs. Southern California Edison, Sierra Pacific Power Company and Nevada Power Company (subsidiaries of NV Energy), HELCO, and KPLC have accounted for 14.2%, 17.6%, 9.2%, and 11.6%, respectively, of our revenues for the year ended December 31, 2013. 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. All of these plants were in commercial operation in 2013, and to date, except in the case of North Brawley power plant, the shortfall amount has not been material. In the case of North Brawley, which operates below its contract capacity level, the purchaser's replacement costs are materially lower than the PPA's energy rate, and therefore we believed no payment is required. 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 the 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 some or all of our domestic power plants refund 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 our domestic power plants, either of which would have an adverse effect on our revenues. Even if a power plant does not lose its Qualifying Facility status, pursuant to a final rule 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 California, 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, recovered energy-based power plants, and Solar PV power plants have benefited, and may benefit in the future, from public policies and government incentives that support renewable energy and enhance the economic feasibility of these projects in regions and countries where we operate. Such policies and incentives include PTCs and ITCs, accelerated depreciation tax benefits, renewable portfolio standards, carbon trading mechanisms, rebates, and mandated feed-in-tariffs, and may include similar or other incentives to end users, distributors, system integrators and manufacturers of geothermal, solar and other power products. Some of these measures have been implemented at the federal level, while others have been implemented by different states within the U.S. or countries outside the U.S. where we operate.

The availability and continuation of these public policies and government incentives have a significant effect on the economics and viability of our development program and continued construction of new geothermal, recovered energy-based and Solar PV power plants. Any changes to such public policies, or any reduction in or elimination or expiration of such government incentives could affect us in different ways. For example, any reduction in, termination or expiration of renewable portfolio standards may result in less demand for generation from our geothermal, recovered energy-based, and Solar PV 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 lack of 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 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. Our revenues for the year ended December 31, 2013, from the power plants utilizing the IID transmission system, were approximately $77.0 million. 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 and any future expansion of our Solar PV plant near the Heber complex.

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. For example, most recently we have announced that Isaac Angel will become our new Chief Executive Officer effective July 1, 2014, replacing Yehudit Bronicki, who served as our Chief Executive Officer for more than 20 years. This change is commensurate with the expected retirement of Lucien Bronicki, our Chief Technology Officer, and the transition of Yoram Bronicki from serving as our President and Chief Operating Officer to the position of Chairman of our Board of Directors. 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. Operations in Israel accounted for approximately 25.2%, 18.0% and 22.9% of our operating expenses in the years ended December 31, 2013, 2012 and 2011, respectively. 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 and November 2012, 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.

If our Parent, Ormat Industries, defaults on its lease agreement with the Israel Land Administration, or is involved in a bankruptcy or similar proceeding, our rights and remedies under certain agreements pursuant to which we acquired our product business and pursuant to which we sublease our land and manufacturing facilities from our parent may be adversely affected.

We acquired our business relating to the manufacture and sale of products for electricity generation and related services from our parent, Ormat Industries. In connection with that acquisition, we entered into a sublease with Ormat Industries for the lease of the land and facilities in Yavne, Israel where our manufacturing and production operations are conducted and where our Israeli offices are located. Under the terms of our parent's lease agreement with the Israel Land Administration our sublease is for a period of twenty-five years less one day. The consent of the Israel Land Administration was obtained for a period of the shorter of (i) 25 years or (ii) the remaining period of the underlying lease agreement with the Israel Land Administration, which terminates between 2018 and 2047. We recently entered into a new lease agreement with Ormat Industries for the sublease of additional manufacturing facilities that were built adjacent to the existing facilities. The agreement will expire on the same date as the abovementioned agreement. If our parent were to breach its obligations to the Israel Land Administration under its lease agreement, the Israel Land Administration could terminate the lease agreement and, consequently, our sublease would terminate as well.

As part of the acquisition described in the preceding paragraph, we also entered into a patent license agreement with Ormat Industries, pursuant to which we were granted an exclusive license for certain patents and trademarks relating to certain technologies that are used in our business. If a bankruptcy case were commenced by or against our parent, it is possible that performance of all or part of the agreements entered into in connection with such acquisition (including the lease of land and facilities described above) could be stayed by the bankruptcy court in Israel or rejected by a liquidator appointed pursuant to the Bankruptcy Ordinance in Israel and thus not be enforceable. Any of these events could have a material and adverse effect on 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.

Those of our directors and executive officers who also hold positions with our parent may have conflicts of interest with respect to matters involving both companies.

Some of our directors and executive officers also hold positions with our parent. Currently, (i) two of our eight directors are directors and/or officers of Ormat Industries, namely Yehudit Bronicki and Gillon Beck, (ii) our Chief Technology Officer, Lucien Bronicki is a director of Ormat Industries, and (iii) two of our executive officers are also executive officers of Ormat Industries, namely our Chief Financial Officer, Doron Blachar, is the Chief Financial Officer of our parent, and our Senior Vice President — Contract Management and Corporate Secretary, Etty Rosner, is the Corporate Secretary of our parent. These directors and officers owe fiduciary duties to both companies and may have conflicts of interest on matters affecting both us and our parent, and in some circumstances may have interests adverse to our interests. See also the changes in our management described above under "Recent Developments".

Our parent or its controlling stockholders may take actions that conflict with your interests.

Ormat Industries holds approximately 60% of our common stock. Because of these holdings, our parent company will be able to exercise control over all matters requiring stockholder approval, including the election of our directors, amendment of our certificate of incorporation and approval of our significant corporate transactions, and they will have significant control over our management and policies. The directors elected by our parent will be able to significantly influence decisions affecting our capital structure, dividend policies, share issuances and repurchases, and other matters presented for action by our directors. This control may have the effect of delaying or preventing changes in control or changes in management, or limiting the ability of our other stockholders to approve transactions that they may deem to be in their best interest.

Certain of our parent company's shareholders, through their ownership of our parent's shares, by contract or otherwise, may also affect our management and policies in various respects. As of February 28, 2014 approximately:

- 19.48% of our parent's ordinary shares were held by Bronicki Investments, a privately held Israeli company that is controlled by Lucien and Yehudit Bronicki.

- 22.50% of our parent's ordinary shares were held by FIMI.

Bronicki Investments and FIMI are parties to a Shareholders Rights Agreement (the "Shareholder Agreement") that, among other things, includes joint voting and other arrangements that affect our parent and in certain cases its subsidiaries, including us and our subsidiaries. The principal impact of that Shareholder Agreement on us and our subsidiaries are undertakings that:

- subject to any applicable law and fiduciary duties, Bronicki Investments and FIMI will use their reasonable efforts to cause an equal number of designees of Bronicki Investments and FIMI to be elected or appointed to our Board of Directors and to the boards of all active subsidiaries of our parent (including our subsidiaries). In the case of our board, FIMI and Bronicki Investments each have the right to designate four members (subject to staged adjustments if either FIMI or Bronicki Investments or both cease to own specified minimum amounts of our parent's ordinary shares, within various ranges specified in the Shareholder Agreement); and subject to any applicable law, use their best efforts to cause (subject to continued holding of certain minimum amounts of our parent's ordinary shares):

the continued service of Yehudit Bronicki as our Chief Executive Officer and of Yoram Bronicki as our President and Chief Operations Officer, in each case for a service period set forth in the Shareholder Agreement. If either Yehudit Bronicki or Yoram Bronicki is unable to fulfill these positions, Bronicki Investments is entitled to appoint to the applicable position another designee;

the appointment of FIMI's designee to serve as our Chairman of the Board for a service period set forth in the Shareholder Agreement; and

after the expiration of the service periods referred to above, the nomination of Bronicki Investments' designee as our Chief Executive Officer or Chairman of the Board (as Bronicki Investments may decide in its sole discretion), and the appointment of FIMI's designee as our Chairman of the Board (if Bronicki Investments' designee serves as Chief Executive Officer) or our Chief Executive Officer (if Bronicki Investments's designee serves as Chairman of the Board).

The persons currently serving as our directors, Chairman of the Board, Chief Executive Officer and President and Chief Operations Officer are as contemplated by the Shareholders Agreement.

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; 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, our parent, Ormat Industries holds approximately 60% 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. On November 10, 2004, we entered into a registration rights agreement with Ormat Industries whereby Ormat Industries may require us to register our common stock held by it or its directors, officers and employees with the SEC or to include our common stock held by it or its directors, officers and employees in an offering and sale by us.

Provisions in our charter documents and Delaware law may delay or prevent 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 do not permit actions by our stockholders by written consent. In addition, 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 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. Our Board of Directors has the right to issue preferred stock without stockholder approval, which could be used to institute a “poison pill” that would work to dilute the stock ownership of a potential hostile acquirer, effectively preventing acquisitions that have not been approved by our Board of Directors. 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. Although we believe these provisions provide for an opportunity to receive a higher bid by requiring potential acquirers to negotiate with our Board of Directors, these provisions apply even if the offer may be considered beneficial by some stockholders.

New 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 new 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 in May 2014 disclosing, among others, whether such minerals originate from the Democratic Republic of Congo or adjoining countries. The implementation of these new requirements could adversely affect the sourcing, availability and pricing of minerals used in the manufacture of certain components incorporated in our products. In addition, to the extent the rules apply to us, we will 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 sublease from Ormat Industries. 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 2013, other than as described below.

On December 24, 2012, Laborers' International Union of North America Local Union No. 783 (LiUNA), an organized labor union, filed a petition in Mono County Superior Court, naming Mono County, California and the Company as defendant and real party in interest, respectively. The petitioners brought this action to challenge the November 13, 2012 decision of the Mono County Board of Supervisors in adopting Resolutions No. 12-78, denying Petitioners' administrative appeal of the Planning Commission's approval of Conditional Use Permit (CUP), adoption of findings under the California Environmental Quality Act (CEQA) and adoption of the final environmental impact report (EIR) for the Mammoth enhancement. The petition asks the court to set aside the approval of the CUP and adoption of the

EIR and cause a new EIR to be prepared and circulated.

The Company believes that the petition is without merit and intends to respond and take necessary legal action to dismiss the proceedings. The Company responded to LiUNA's petition. Filing of the petition in and of itself does not have any immediate adverse implications for the Mammoth enhancement.

In January 2014, the Company 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 the Company submitted fraudulent applications and certifications to obtain grants. While the United States Department of Justice has declined to intervene, the former employees may proceed on their own. While we believe the allegations are without merit, we are investigating the allegations and evaluating and assessing the exposure to the Company, if any. The Company does not believe that the allegations of the lawsuit have any merit and will defend itself vigorously if served.

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". Public trading of our stock commenced on November 11, 2004. Prior to that, there was no public market for our stock. As of February 27, 2014, there were 16 record holders of the Company's common stock. On February 27, 2014, our stock's closing price as reported on the NYSE was $27.30 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
May 8, 2012	$ 0.04	May 21, 2012	May 30, 2012
August 1, 2012	$ 0.04	August 14, 2012	August 23, 2012
August 6, 2013	$ 0.04	August 19, 2013	August 29, 2013
November 6, 2013	$ 0.04	November 20, 2013	December 4, 2013

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, 2012 and 2013, and from January 1, 2014 until February 27, 2014:

	First Quarter 2012	Second Quarter 2012	Third Quarter 2012	Fourth Quarter 2012	First Quarter 2013	Second Quarter 2013	Third Quarter 2013	Fourth Quarter 2013	January 1 to February 27, 2014
High	$ 21.05	$ 22.24	$ 21.50	$ 20.80	$ 21.75	$ 23.89	$ 27.61	$ 27.95	27.33
Low:	$ 16.01	$ 20.60	$ 17.61	$ 16.67	$ 19.55	$ 19.80	$ 22.55	$ 25.00	24.27

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, 2013 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, 2013

	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	0.0	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, 2013, 2012 and 2011 and as of December 31, 2013 and 2012 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, 2010 and 2009 and as of December 31, 2011, 2010 and 2009 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,				
	2013	2012 As Revised	2011	2010	2009
	(Dollars in thousands, except per share data)				
Statements of Operations Data:					
Revenues:					
Electricity	$329,747	$314,894	$312,296	$279,947	$241,623
Product	203,492	186,879	113,160	81,410	159,389
Total revenues	533,239	501,773	425,456	361,357	401,012
Cost of revenues:					
Electricity	232,874	237,415	235,609	233,894	172,453
Product	140,547	135,346	76,072	53,277	112,450
Total cost of revenues	373,421	372,761	311,681	287,171	284,903
Gross margin	159,818	129,012	113,775	74,186	116,109
Operating expenses:					
Research and development expenses	4,965	6,108	8,801	10,120	10,502
Selling and marketing expenses	24,613	15,718	16,053	13,302	14,222
General and administrative expenses	29,188	28,066	27,366	26,937	25,908
Impairment charges	—	236,377	—	—	—
Write-off of unsuccessful exploration activities	4,094	2,639	—	3,050	2,367
Operating income (loss)	96,958	(159,896)	61,555	20,777	63,110
Other income (expense):					
Interest income	1,332	1,201	1,427	343	639
Interest expense, net	(73,776)	(64,069)	(69,459)	(40,473)	(16,241)
Foreign currency translation and transaction gains (losses)	5,085	242	(1,350)	1,557	(1,695)
Income attributable to sale of tax benefits	19,945	10,127	11,474	8,729	15,515
Gain on acquisition of controlling interest	—	—	—	36,928	—

Gain from extinguishment of liability	—	—	—	—	13,348
Other non-operating income, net	1,592	590	671	130	200
Income (loss) from continuing operations, before income taxes and equity in income (losses) of investees	51,136	(211,805)	4,318	27,991	74,876
Income tax benefit (provision)	(13,552)	(1,827)	(48,240)	1,700	(14,714)
Equity in income (losses) of investees, net	(250)	(2,522)	(959)	998	2,136
Income (loss) from continuing operations	37,334	(216,154)	(44,881)	30,689	62,298
Discontinued operations:					
Income from discontinued operations (including gain on disposal of $3,646, $0, $0, $6,336 and $0, respectively)	5,311	4,811	2,452	9,141	6,971
Income tax provision	(614)	(1,264)	(295)	(2,602)	(716)
Total income from discontinued operations	4,697	3,547	2,157	6,539	6,255
Net income (loss)	42,031	(212,607)	(42,724)	37,228	68,553
Net loss (income) attributable to noncontrolling interest	(793)	(414)	(332)	90	298
Net income (loss) attributable to the Company's stockholders	$41,238	$(213,021)	$(43,056)	$37,318	$68,851

86

	Year Ended December 31,				
	2013	2012 As Revised	2011	2010	2009
	(Dollars in thousands, except per share data)				
Earnings (losses) per share attributable to the Company's stockholders:					
Basic:					
Income (loss) from continuing operations	$0.81	$(4.77)	$(1.00)	$0.67	$1.38
Discontinued operations	0.10	0.08	0.05	0.15	0.14
Net income (loss)	$0.91	$(4.69)	$(0.95)	$0.82	$1.52
Diluted:					
Income (loss) from continuing operations	$0.81	$(4.77)	$(1.00)	$0.67	$1.37
Discontinued operations	0.10	0.08	0.05	0.15	0.14
Net income (loss)	$0.91	$(4.69)	$(0.95)	$0.82	$1.51
Weighted average number of shares used in computation of earnings (losses) per share attributable to the Company's stockholders:					
Basic	45,440	45,431	45,431	45,431	45,391
Diluted	45,475	45,431	45,431	45,452	45,533
Cash dividend per share declared during the year	$0.08	$0.08	$0.13	$0.27	$0.25
Balance Sheet Data (at end of year):					
Cash and cash equivalents	$57,354	66,628	99,886	82,815	46,307
Working capital	103,001	64,100	98,415	66,932	55,652
Property, plant and equipment, net (including construction-in process)	1,741,163	1,649,014	1,889,083	1,696,101	1,517,288
Total assets	2,159,433	2,087,523	2,314,718	2,043,328	1,864,193
Long-term debt (including current portion)	1,077,857	1,030,928	1,025,010	789,669	624,442
Notes payable to Parent (including current portion)	—	—	—	—	9,600
Equity	745,111	695,607	906,644	945,227	911,695

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. We have expanded our activities in the Electricity Segment to include the ownership and operation of power plants that produce electricity generated by Solar PV systems that we do not manufacture; 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, 2013, our total revenues increased by 6.3% (from $501.8 million to $533.2 million) over the previous year.

For the year ended December 31, 2013, Electricity Segment revenues were $329.7 million, compared to $314.9 million for the year ended December 31, 2012, an increase of 4.7%, and Product Segment revenues for the year ended December 31, 2013 were $203.5 million, compared to $186.9 million during the year ended December 31, 2012, an increase of 8.9%.

During the years ended December 31, 2013 and 2012, our consolidated power plants generated 4,253,489 MWh and 3,942,293 MWh, respectively, an increase of 7.9%

For the year ended December 31, 2013, our Electricity Segment represented approximately 61.8% of our total revenues (62.8% in 2012), while our Product Segment represented approximately 38.2% of our total revenues (37.2% in 2012).

In the year ended December 31, 2013, approximately 68.5% 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 (the California SO#4 PPAs) change based primarily 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 have reduced our exposure to fluctuations in the price of natural gas and oil until December 31, 2014 by entering into derivatives contracts. In the year ended December 31, 2013, we recorded a loss of $5.0 million in electricity revenues related to these contracts.

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 our 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. During the 1990s, growth and development in the geothermal industry occurred primarily in foreign markets and only minimal growth and development occurred in the United States. 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 and in the Solar PV sector.

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. Federal legislation or additional federal regulations addressing climate change are possible. 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.

Outside of the United States, in November 2012 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 and we are currently negotiating a fixed price for the 25 MW PPA as well. 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 likely will continue to be used to manage volatility in revenues, net profit and certain other line items in our financial statements.

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 swap transactions at a fixed average price of $4.0 per MMbtu in 2013 and $4.07 per MMbtu in 2014 to reduce further our exposure to fluctuations in natural gas prices through December 31, 2014. Our use of derivative instruments for this purpose has increased, and likely will continue to be used to manage volatility in revenues, net profit and certain other items in our financial statements.

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, economic and financial risks, which vary by country. As of the date of this annual report, those risks include 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 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.

FERC's regulations under PURPA allow FERC 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 68.5% of our Electricity revenues for the year ended December 31, 2013 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 the years ended December 31, 2012 and 2013, we entered into derivative transactions in an attempt to reduce our exposure to fluctuations in the prices of natural gas and oil from these PPA until December 31, 2014.

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 2011 and 2012, 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 15, 2014, 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,		
	2013	2012	2011	2013	2012	2011
Revenues:						
Electricity	$329,747	$314,894	$312,296	61.8 %	62.8 %	73.4 %
Product	203,492	186,879	113,160	38.2	37.2	26.6
Total	$533,239	$501,773	$425,456	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 (dollars in thousands)			% of Revenues for Period Indicated		
	Year Ended December 31,			Year Ended December 31,		
	2013	2012	2011	2013	2012	2011
Electricity Segment:						
United States	$246,112	$246,070	$249,740	74.6 %	78.1 %	80.0 %
Foreign	83,635	68,824	62,556	25.4	21.9	20.0
Total	$329,747	$314,894	$312,296	100.0%	100.0%	100.0%
Product Segment:						
United States	$55,101	$21,374	$—	27.1 %	11.4 %	0.0 %
Foreign	148,391	165,505	113,160	72.9	88.6	100.0
Total	$203,492	$186,879	$113,160	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 4.2% and 4.3% of Electricity Segment revenues for the years ended December 31, 2013 and December 31, 2012, 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, Cash Equivalents, and Short-Term Bank Deposit

Our cash, cash equivalents, and a short-term bank deposit as of December 31, 2013 decreased to $57.4 million from $69.6 million as of December 31, 2012. This decrease is principally due to: (i) our use of $220.1 million to fund capital expenditures; (ii) repayment of $68.4 million of long-term debt; (iii) $13.4 million of cash paid to the Class B membership units of OPC (see “OPC Transaction” below); and (iv) $11.9 million of cash used to repurchase portion of Ormat Funding LLC (OFC) Senior Secured Notes. This decrease was partially offset by: (i) an additional $90.0 million of net proceeds from the disbursement from Tranche II and III of the OPIC Loan, as described below under “Non-Recourse and Limited-Recourse Third-Party Debt”; (ii) $86.8 million derived from operating activities during the year ended December 31, 2013; (iii) a net change in restricted cash and cash equivalents of $25.5 million; (iv) $31.4 million of net proceeds from the ORTP Transaction (see “ORTP Transaction” below); (v) net proceeds of $38.4 million we drew down under our revolving credit lines with commercial banks; (vi) a cash grant of $14.7 million received from the U.S. Treasury under Section 1603 of the ARRA in the third quarter of 2013 relating to our Brawley geothermal power plant; and (vii) net proceeds of $7.7 million from the sale of our interest in the Momotombo power plant. Our corporate borrowing capacity under committed lines of credit with different commercial banks as of December 31, 2013 was $485.1 million, as described below in “Liquidity and Capital Resources”, of which we have utilized $325.2 million (including $210.9 million of letters of credit) as of December 31, 2013.

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, 2013, and 2012, we determined that the geothermal resource at four and five 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 $4,094,000 and $2,639,000 of capitalized costs during the years ended December 31, 2013 and 2012, 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 $69,639,000 and $67,565,000 at December 31, 2013 and 2012, respectively. Of this amount, $30,141,000 and $33,985,000 relates to up-front bonus payments at December 31, 2013 and 2012, 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, 2013, 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 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 are these with a 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,		
	2013	**2012 As Revised**	**2011**
	(Dollars in thousands, except per share data)		
Statements of Operations Historical Data:			
Revenues:			
Electricity	$329,747	$314,894	$312,296
Product	203,492	186,879	113,160
	533,239	501,773	425,456
Cost of revenues:			
Electricity	232,874	237,415	235,609
Product	140,547	135,346	76,072
	373,421	372,761	311,681
Gross margin:			
Electricity	96,873	77,479	76,687
Product	62,945	51,533	37,088
	159,818	129,012	113,775
Operating expenses:			
Research and development expenses	4,965	6,108	8,801
Selling and marketing expenses	24,613	15,718	16,053
General and administrative expenses	29,188	28,066	27,366
Impairment charges	—	236,377	—
Write-off of unsuccessful exploration activities	4,094	2,639	—
Operating income (loss)	96,958	(159,896)	61,555
Other income (expense):			
Interest income	1,332	1,201	1,427
Interest expense, net	(73,776)	(64,069)	(69,459)
Foreign currency translation and transaction gains (losses)	5,085	242	(1,350)
Income attributable to sale of tax benefits	19,945	10,127	11,474
Other non-operating income, net	1,592	590	671
Income (loss) from continuing operations, before income taxes and equity in income of investees	51,136	(211,805)	4,318
Income tax provision	(13,552)	(1,827)	(48,240)
Equity in losses of investees, net	(250)	(2,522)	(959)

Income (loss) from continuing operations	37,334	(216,154)	(44,881)
Discontinued operations:			
Income from discontinued operations (including gain on disposal of $3,646, $0 and $0, respectively)	5,311	4,811	2,452
Income tax provision	(614)	(1,264)	(295)
Total income from discontinued operations	4,697	3,547	2,157
Net income (loss)	42,031	(212,607)	(42,724)
Net income attributable to noncontrolling interest	(793)	(414)	(332)
Net income (loss) attributable to the Company's stockholders	$41,238	$(213,021)	$(43,056)
Earnings (loss) per share attributable to the Company's stockholders:			
Basic:			
Income (loss) from continuing operations	$0.81	$(4.77)	$(1.00)
Discontinued operations	0.10	0.08	0.05
Net Income (loss)	$0.91	$(4.69)	$(0.95)
Diluted:			
Income (loss) from continuing operations	$0.81	$(4.77)	$(1.00)
Discontinued operations	0.10	0.08	0.05
Net Income (loss)	$0.91	$(4.69)	$(0.95)
Weighted average number of shares used in computation of earnings (loss) per share attributable to the Company's stockholders:			
Basic	45,440	45,431	45,431
Diluted	45,475	45,431	45,431

	Year Ended December 31,		
	2013	2012 As Revised	2011
Statements of Operations Percentage Data:			
Revenues:			
Electricity	61.8 %	62.8 %	73.4 %
Product	38.2	37.2	26.6
	100.00	100.00	100.00
Cost of revenues:			
Electricity	70.6	75.4	75.4
Product	69.1	72.4	67.2
	70.0	74.3	73.3
Gross margin:			
Electricity	29.4	24.6	24.6
Product	30.9	27.6	32.8
	30.0	25.7	26.7
Operating expenses:			
Research and development expenses	0.9	1.2	2.1
Selling and marketing expenses	4.6	3.1	3.8
General and administrative expenses	5.4	5.6	6.4
Impairment charges	0.0	47.1	0.0
Write-off of unsuccessful exploration activities	0.8	0.5	0.0
Operating income (loss)	18.2	(31.9)	14.5
Other income (expense):			
Interest income	0.2	0.2	0.3
Interest expense, net	(13.7)	(12.8)	(16.3)
Foreign currency translation and transaction gains (losses)	1.0	0.0	(0.3)
Income attributable to sale of tax benefits	3.7	2.0	2.7
Other non-operating income, net	0.3	0.1	0.2
Income (loss) from continuing operations, before income taxes and equity in income (losses) of investees	9.6	(42.2)	1.0
Income tax provision	(2.5)	(0.4)	(11.3)
Equity in losses of investees, net	(0.0)	(0.5)	(0.2)
Income (loss) from continuing operations	7.0	(43.1)	(10.5)
Discontinued operations:			
Income from discontinued operations (including gain on disposal of $3,646, $0 and $0, respectively)	1.0	1.0	0.6
Income tax provision	(0.1)	(0.3)	(0.1)
Total income from discontinued operations	0.9	0.7	0.5
Net income (loss)	7.9	(42.4)	(10.0)
Net income attributable to noncontrolling interest	(0.1)	(0.1)	(0.1)
Net income (loss) attributable to the Company's stockholders	7.7 %	(42.5)%	(10.1)%

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 $2.3 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 an 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 a 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 interest capitalized to our projects under development and construction which decreased which by $4.4 million.

Foreign Currency Translation and Transaction Gains

Foreign currency translation and transactions 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 of jurisdictions outside of 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 $114.8 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 $114.8 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 $114.8 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. If sufficient evidence of our ability to generate taxable income is established in the future, we may be required to reduce this valuation allowance, resulting in income tax benefits in our consolidated statement of operations.

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 $254.6 million was principally attributable to a $253.6 million increase in income from continuing operations, as discussed above.

Comparison of the Year Ended December 31, 2012 and the Year Ended December 31, 2011

Total Revenues

Total revenues for the year ended December 31, 2012 were $501.8 million, compared to $425.5 million for the year ended December 31, 2011, which represented a 17.9% increase in total revenues. This increase was principally attributable to our Product Segment, in which revenues increased by 65.1% over the same period in 2011, principally due to a single order of $130.0 million referred to below, which we received in 2011.

Electricity Segment

Revenues attributable to our Electricity Segment for the year ended December 31, 2012 were $314.9 million, compared to $312.3 million for the year ended December 31, 2011, which represented a 0.8% increase in such revenues. This increase was primarily due to: (i) $23.5 million in revenues from our Tuscarora and McGinness Hills power plants, which commenced commercial operations in January 2012 and July 2012, respectively; (ii) a $2.1 million net increase in revenues from other power plants; and (iii) a net gain of $2.2 million on derivative contracts on oil and natural gas prices, which are described under "Recent Developments" in Item 1 — "Business". This increase was offset by a $25.2 million decrease resulting from the impact of low natural gas prices on the energy rates in our SO#4 PPAs in California, which in the beginning of May 2012 changed from a fixed rate to a variable rate that is subject to the impact of fluctuations in natural gas prices. The generation of power in our power plants increased by 7.0% from 3,683,369 MWh in the year ended December 31, 2011 to 3,942,293 MWh in the year ended December 31, 2012. Revenues derived from the North Brawley power plant were $15.7 million and $15.3 million, respectively, in the years ended December 31, 2012 and 2011.

Product Segment

Revenues attributable to our Product Segment for the year ended December 31, 2012 were $186.9 million, compared to $113.2 million for the year ended December 31, 2011, which represented a 65.1% increase. The increase in our Product Segment revenues reflects the increase in new customer orders that we secured in 2011 and 2012, largely attributable to the $130.0 million order we received from Mighty River Power Limited for the Ngatamariki Geothermal Field in New Zealand, which was completed in June 2013.

Total Cost of Revenues

Total cost of revenues for the year ended December 31, 2012 was $372.8 million, compared to $311.7 million for the year ended December 31, 2011, which represented a 19.6% increase. This was primarily due to the increase in cost of revenues from our Product Segment. As a percentage of total revenues, our total cost of revenues for the year ended December 31, 2012 was 74.3%, compared to 73.3% for the year ended December 31, 2011.

Electricity Segment

Total cost of revenues attributable to our Electricity Segment for the year ended December 31, 2012 was $237.4 million, compared to $235.6 million for the year ended December 31, 2011, which represented a 0.8% increase. This slight increase despite the additional cost of revenues from our new power plants, Tuscarora and McGinness Hills which commenced commercial operations in January 2012 and July 2012, respectively, is the result of lower maintenance costs in most of our power plants and specifically at our North Brawley power plant, where we incurred costs of $29.2 million associated with operating and maintaining the plant in the year ended December 31, 2012, compared to $41.8 million in the year ended December 31, 2011. We were able to lower such costs because we were able to improve our operating efficiencies, particularly in the maintenance of our well fields. Cost of revenues for the year ended December 31, 2012 includes $3.3 million of a net proceeds mining tax imposed on us based on an audit performed by the State of Nevada for the years ended December 31, 2008, 2009 and 2010. Although we paid this amount we appealed the decision of the State of Nevada in January 2013 and we believe it is likely that our appeal will be successful, in whole or in part. The cost per MWh for the year ended December 31, 2012, decreased compared to the year ended December 31, 2011. As a percentage of total electricity revenues, the total cost of revenues attributable to our Electricity Segment was 75.4% for the years ended December 2012 and 2011, respectively.

Product Segment

Total cost of revenues attributable to our Product Segment for the year ended December 31, 2012 was $135.3 million, compared to $76.1 million for the year ended December 31, 2011, which represented a 77.9% increase. This increase is attributable to a significant increase in product revenues, as described above. As a percentage of total Product Segment revenues, our total cost of revenues attributable to this segment for the year ended December 31, 2012 was 72.4%, compared to 67.2% for the year ended December 31, 2011. This increase is mainly attributable to: (i) the recognition of revenues in the amount of $3.0 million in the year ended December 31, 2012, compared to $12.1 million in the year ended December 31, 2011, relating to an experimental REG plant specifically designed to use the residual energy from the vaporization process at LNG regasification terminals in Spain in the year ended December 31, 2012, with virtually no associated cost of revenues (since the related costs were included in research and development costs in previous years); (ii) a different product mix; and (iii) different margins in the various sales contracts. Excluding the impact of the revenues relating to the LNG energy recovery unit in Spain, the Product Segment total cost of revenues as a percentage of total Product Segment revenues for the year ended December 31, 2012 would have been 74.0%, compared to 75.2% for the year ended December 31, 2011.

Research and Development Expenses

Research and development expenses for the year ended December 31, 2012 were $6.1 million, compared to $8.8 million for the year ended December 31, 2011, which represented a 30.6% decrease. This decrease was primarily attributable to the costs incurred in the year ended December 31, 2011 in respect of an experimental REG plant specifically designed to use the residual energy from the vaporization process at LNG regasification terminals which was completed in 2011. The research and development expenses are net of grants from the DOE in the amount of $0.7 million and $1.1 million for the years ended December 31, 2012 and 2011, respectively, with respect to the EGS project.

Selling and Marketing Expenses

Selling and marketing expenses for the year ended December 31, 2012 were $15.7 million, compared to $16.1 million for the year ended December 31, 2011, which represented a 2.1% decrease. The decrease resulted from a $1.7 million termination fee to NV Energy for the year ended December 31, 2011, as part of the termination agreement of the PPA and joint operating agreement for the Carson Lake geothermal project, offset by additional selling and marketing expenses associated with the increased Product Segment revenues. Selling and marketing expenses for the year ended December 31, 2012 constituted 3.1% of total revenues for such year, compared to 3.8% for the year ended December 31, 2011.

General and Administrative Expenses

General and administrative expenses for the year ended December 31, 2012 were $28.1 million, compared to $27.4 million for the year ended December 31, 2011, which represented a 2.6% increase. General and administrative expenses for the year ended December 31, 2012, constituted 5.6% of total revenues for such year, compared to 6.4% for the year ended December 31, 2011.

Impairment Charges

Impairment charges for the year ended December 31, 2012 were $236.4 million. There were no impairment charges for the year ended December 31, 2011.

We evaluate long-lived assets, including power plants, for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. Such evaluations include estimates of future cash flows. If actual cash flows differ significantly from our current estimates, a material impairment charge may be required in the future.

During the fourth quarter of 2012, our North Brawley power plant was tested for recoverability due to the low output and higher than expected operating costs and was written down to a fair value of $32.0 million. The impairment loss of $229.1 million is presented in our consolidated statement of operations and comprehensive income (loss) under “Impairment Charges”.

During the third quarter of 2012, our OREG 4 power plant was tested for recoverability due to continued low output and was written down to a fair value of $3.6 million. The impairment loss of $7.3 million is presented in our consolidated statement of operations and comprehensive income (loss) under “Impairment Charges”.

For more details, see Note 7 to our consolidated financial statements set forth in Item 8 of this annual report.

Write-off of Unsuccessful Exploration Activities

Write-off of unsuccessful exploration activities for the year ended December 31, 2012 was $2.6 million. This 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. There were no write-offs of unsuccessful exploration activities for the year ended December 31, 2011.

Operating Income (Loss)

Operating loss for the year ended December 31, 2012 was $159.9 million, compared to operating income of $61.6 million for the year ended December 31, 2011. The operating loss was principally attributable to the impairment charges in the total amount of $236.4 million, as described above, partially offset by an increase in our gross margin. Operating loss attributable to our Electricity Segment for the year ended December 31, 2012 was $190.0 million, compared to operating income of $42.9 million for the year ended December 31, 2011. Operating income attributable to our Product Segment for the year ended December 31, 2012 was $30.1 million, compared to $18.6 million for the year ended December 31, 2011.

Interest Expense, Net

Interest expense, net, for the year ended December 31, 2012 was $64.1 million, compared to $69.5 million for the year ended December 31, 2011, which represented a 7.8% decrease. This $5.4 million decrease was primarily due to a

$16.4 million loss, in the year ended December 31, 2011, on interest rate lock transactions, relating to the OFC 2 Senior Secured Notes, which were not accounted for as hedge transactions and an increase of $0.3 million in interest capitalized to projects as a result of increased aggregate investment in projects under construction, partially offset by additional interest expense mainly as a result of the issuance of Series A Senior Secured Notes in October 2011 by OFC 2, the full year impact in 2012 of the issuance of the Senior Unsecured Bonds in February 2011, and the $1.8 million of costs associated with the early repayment of part of the DEG loan in November 2012, as described below under “Liquidity and Capital Resources”.

Income Attributable to Sale of Tax Benefits

Income attributable to the sale of tax benefits to institutional equity investors (as described in “OPC Transaction” below) for the year ended December 31, 2012 was $10.1 million, compared to $11.5 million for the year ended December 31, 2011. This income represents the value of PTCs and taxable income or loss generated by OPC and allocated to the investors. The decrease was due to lower depreciation for tax purposes as a result of declining depreciation rates utilizing MACRS.

Income Taxes

Income tax provision for the year ended December 31, 2012 was $1.8 million, compared to $48.2 million for the year ended December 31, 2011. The decrease in income tax provision primarily resulted from the decrease in income before taxes.

For the year ended December 31, 2012 and 2011, we recorded a valuation allowance in the amount of approximately $113.6 million and $61.5 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, 2012 we had U.S. federal NOLs in the amount of approximately $267.6 million, state NOLs in the amount of approximately $193.4 million, and unutilized tax credits of approximately $70.4 million, all of which can be utilized over 20 years. The related deferred tax assets totaled approximately $176.1 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 $113.6 million was recorded against the U.S. deferred tax assets as of December 31, 2012 as, at that point in time, we believed it is more likely than not that the deferred tax assets will not be realized. If sufficient evidence of our ability to generate taxable income is established in the future, we may be required to reduce this valuation allowance, resulting in income tax benefits in our consolidated statement of operations.

Loss from Continuing Operations

Loss from continuing operations for the year ended December 31, 2012 was $216.2 million, compared to $44.9 million for the year ended December 31, 2011. The increase in the loss from continuing operations of $171.3 million was principally attributable to a $221.5 million decrease in operating income, as discussed above, offset by: (i) a $46.4 million decrease in income tax provision; and (ii) a $5.4 million decrease in interest expense, net.

Discontinued Operations

In June 2013, Ormat Holding Corp. sold its stake 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. The operations of the MPC for the year ended December 31, 2012 and 2011, have been included in discontinued operations. Discontinued operations for the year ended December 31, 2012 and 2011 include revenues of $12.6 million and 11.6 million, respectively, of MPC.

Net loss

Net loss for the year ended December 31, 2012 was $212.6 million, compared to $42.7 million for the year ended December 31, 2011. The increase in net loss of $169.9 million was principally attributable to increase in the loss from continuing operations in the amount of $164.7 million, 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, short term borrowing under our lines of credit and cash grants we received under the ARRA. We have utilized this cash to develop and construct power generation plants, to fund our acquisitions, and to meet our other cash and liquidity needs.

As of December 31, 2013, we had access to the following sources of funds: (i) $57.4 million in cash, cash equivalents and a short-term bank deposit of which $47.4 million is related to foreign jurisdictions; and (ii) $160.0 million of unused corporate borrowing capacity under existing lines of credit with different commercial banks.

Our estimated capital needs for 2014 include approximately $230.0 million for capital expenditures on new projects under development or construction, exploration activity, operating projects, and machinery and equipment, as well as $78.6 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; (iii) future project financing and refinancing (including construction loans); and (iv) cash grants available to us under the ARRA in respect of the new geothermal power plants that were placed in service before the end of 2013 and the Heber Solar PV plant. 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 believe that the transition to variable energy prices under the Ormesa and Mammoth PPAs and the impact of the currently low natural gas prices on the revenues under these PPAs may cause OFC to not meet the DSCR ratio requirements for making distributions, but we do believe that there will not be an event of default by OFC. As of December 31, 2013 (the last measurement date of the covenants), the actual historical 12-month DSCR was 1.29. There were $90.8 million and $114.1 million of OFC Senior Secured Notes outstanding as of December 31, 2013 and December 31, 2012, respectively.

In January 2014, we acquired from OFC noteholders OFC Senior Secured Notes with an outstanding aggregate principal amount of $13.2 million. We will recognize a gain of approximately $0.3 million in the first quarter of 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, 2013, the actual historical 12-month DSCR was 1.3. There were $66.2 million and $76.5 million of OrCal Senior Secured Notes outstanding as of December 31, 2013 and December 31, 2012, respectively.

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.

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 $147.4 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.

Issuance of the Series B Notes is dependent on the Jersey Valley power plant reaching certain operational targets in addition to the other conditions precedent noted above. If issued, the aggregate principal amount of the Series B Notes will not exceed $28.0 million, and such proceeds would be used to finance a portion of the construction costs of Phase I of the Jersey Valley power plant.

The OFC 2 Issuers have sole discretion regarding whether to commence construction of Phase II of any of the Jersey Valley, McGinness Hills and Tuscarora power plants. If Phase II construction is undertaken for any of the power plants, the OFC 2 Issuers may issue Phase II tranches of Notes, comprised of one or more of Series C Notes, Series D Notes, Series E Notes and Series F Notes, to finance a portion of the construction costs of such Phase II of any facility. The aggregate principal amount of all Phase II Notes may not exceed $170.0 million. The aggregate principal amount of each series of Notes comprising a Phase II tranche will be determined by the OFC 2 Issuers in their sole discretion provided that certain financial ratios are satisfied pursuant to the terms of the Note Purchase Agreement and subject to the aggregate limit noted above.

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, 2013 (the last measurement date of the covenants), the historical actual DSCR was 1.79 and the pro-forma 12-month DSCR was 2.25. There were $144.5 million and $150.5 million of OFC 2 Senior Secured Notes outstanding as of December 31, 2013 and 2012, respectively.

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

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

In August 2012, OrPower 4, 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 of $80.2 million and matures on December 15, 2030 and Tranche II, which has an outstanding balance of $174.7 million and matures on June 15, 2030, is 6.31%. In November 2013 we fixed the interest rate applicable to Tranche III. The fixed interest rate for Tranche III, which has an outstanding balance of $45.0 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 $39.5 million as of December 31, 2013, 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 will become effective on December 15, 2014.

As of December 31, 2013, $299.9 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 TCW Global Project Fund II, Ltd. (TCW). The loan bears interest at a rate of 9.83%, will mature on June 15, 2016, and is payable in 28 quarterly installments. There are various restrictive covenants under the loan, which include: (i) a projected 12-month DSCR of not less than 1.2; and (ii) a long-term debt to equity ratio not to exceed 4.0 (both of which are measured quarterly). If Ortitlan fails to comply with these financial ratios it will be prohibited from making distributions to its shareholders. In addition, subject to certain cure rights, such failure will constitute an event of default. As of December 31, 2013, the projected 12-month DSCR was 1.61, the debt to equity ratio was 2.21, and $31.5 million of this loan was outstanding.

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 March 31, 2014, pursuant to Amendment No. 1 to the amended and restated agreement). The aggregate amount available under the credit agreement was increased from $39.0 million to $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, 2013: (i) the actual 12-month debt to EBITDA ratio was 2.58; (ii) the 12-month DSCR was 2.47; and (iii) the distribution leverage ratio was 1.34. 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, 2013, letters of credit in the aggregate amount of $45.6 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. 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 2.58; (ii) the 12-month DSCR was 2.47; and (iii) the distribution leverage ratio was 1.34. 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, 2013, letters of credit in the aggregate amount of $20.8 million remain issued and outstanding under this committed credit agreement.

Credit Agreements. We also have committed credit agreements with five other commercial banks for an aggregate amount of $410.1 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 $283.0 million; and (ii) the issuance of one or more letters of credit in the amount of up to $202.1 million. The credit agreements mature between end of March 2014 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, 2013, loans in the total amount of $112.0 were outstanding, and letters of credit with an aggregate stated amount of $144.6 million were issued and outstanding under these credit agreements. The $112.0 million in loans are for terms of three months or less and bear interest at a weighted average rate of 2.56%.

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, 2013, $7.5 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, 2013, $13.3 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, 2013, $12.0 million was outstanding under this loan.

We have a $50.0 million term loan with a commercial bank, which matures on November 10, 2014, is payable in ten semi-annual installments commencing May 10, 2010, and bears interest at 6-month LIBOR plus 3.25%. As of December 31, 2013, $10.0 million was outstanding under this loan.

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%. Currently, $39.5 million is outstanding under the DEG Loan (out of which $32.5 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, 2013: (i) total equity was $745.1 million and the actual equity to total assets ratio was 4.49% and (ii) the 12-month debt, net of cash, cash equivalents, and short-term bank deposits to Adjusted EBITDA ratio was 1,020.5 million. During the year ended December 31, 2013, we distributed interim dividends in an aggregate amount of $3.6 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, 2013, committed letters of credit in the aggregate amount of $248.9 million remained issued and outstanding, out of which $210.9 million were issued under the credit agreements with Union Bank, HSBC and five of the commercial banks as described under "Full-Recourse Third Party Debt". In addition, $38.0 million were issued under non-committed lines of credit.

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.

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% 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 $5.0 million as of December 31, 2013. 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**
May 8, 2012	$ 0.04	May 21, 2012	May 30, 2012
August 1, 2012	$ 0.04	August 14, 2012	August 23, 2012
August 6, 2013	$ 0.04	August 19, 2013	August 29, 2013
November 6, 2013	$ 0.04	November 20, 2013	December 4, 2013

Historical Cash Flows

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

	Year Ended December 31,		
	2013	**2012**	**2011**
	(Dollars in thousands)		
Net cash provided by operating activities	$86,760	$89,471	$132,734
Net cash used in investing activities	(157,153)	(100,790)	(341,002)
Net cash provided by (used in) financing activities	61,119	(21,939)	225,339
Net change in cash and cash equivalents	(9,274)	(33,258)	17,071

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, and (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, as described above; (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 our Brawley geothermal power plant; and (iii) $7.7 million cash received 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); and (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.

For the Year Ended December 31, 2012

Net cash provided by operating activities for the year ended December 31, 2012 was $89.5 million, compared to $132.7 million for the year ended December 31, 2011. The net decrease of $43.2 million resulted primarily from: (i) an increase in net loss from $42.7 million in the year ended December 31, 2011 to $206.0 million in the year ended December 31, 2012, as described above; (ii) a decrease in deferred income tax provision, net of $11.3 million in the year ended December 31, 2012, compared to an increase of $38.1 million in the year ended December 31, 2011; and (iii) a decrease in billing in excess of costs and estimated earnings on uncompleted contracts, net of $13.3 million in our Product Segment in the year ended December 31, 2012, compared to an increase of $32.1 million in the year ended December 31, 2011, as a result of timing in billing of our customers. Such decrease was partially offset by an impairment charge of $236.4 million, as described above.

Net cash used in investing activities for the year ended December 31, 2012 was $100.8 million, compared to $341.0 million for the year ended December 31, 2011. The principal factors that affected our net cash used in investing activities during the year ended December 31, 2012 were capital expenditures of $233.0 million, primarily for our facilities under construction offset by: (i) a cash grant in the amount of $119.2 million received in the year ended December 31, 2012 from the U.S. Treasury under Section 1603 of the ARRA relating to the enhancement of our Puna geothermal complex and to our Jersey Valley, Tuscarora, and McGinness Hills geothermal power plants; and (ii) a net decrease of $18.8 million in marketable securities.

Net cash used in financing activities for the year ended December 31, 2012 was $21.9 million, compared to net cash provided by financing activities of $225.3 million for the year ended December 31, 2011. The principal factors that affected the net cash used in financing activities during the year ended December 31, 2012 were: (i) a net decrease of $140.4 million against our revolving lines of credit with commercial banks; (ii) the repayment of long-term debt in the amount of $74.5 million; (iii) $14.9 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. This decrease was partially offset due to $214.1 million net proceeds from the disbursements of $85.0 million representing the full amount of Tranche I of the OPIC Loan, and $135.0 million from Tranche II of the OPIC Loan, as described above under “Non-Recourse and Limited-Recourse Third-Party Debt”.

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, excluding impairment of long-lived assets and including depreciation and amortization. EBITDA and adjusted EBITDA are not measurements of financial performance or liquidity under GAAP and should not be considered as an alternative to cash flow from operating activities or as a measure of liquidity or an alternative to net earnings as indicators of our operating performance or any other measures of performance derived in accordance with GAAP. EBITDA and adjusted EBITDA are presented because we believe they are frequently used by securities analysts, investors and other interested parties in the evaluation of a company's ability to service and/or incur debt. However, other companies in our industry may calculate EBITDA and adjusted EBITDA differently than we do. This information should not be considered in isolation 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, 2013 was $227.1 million, compared to $185.7 million for the year ended December 31, 2012 and $166.7 million for the year ended December 31, 2011.

The following table reconciles net cash provided by operating activities to EBITDA and adjusted EBITDA, for the years ended December 31, 2013, 2012, and 2011:

	Year Ended December 31,		
	2013	2012	2011
	(in thousands)		
Net cash provided by operating activities	$86,760	$89,471	$132,734
Adjusted for:			
Interest expense, net (excluding amortization of deferred financing costs)	67,677	57,711	65,920
Interest income	(1,332)	(1,201)	(1,427)
Income tax provision (benefit)	14,166	3,091	48,535
Adjustments to reconcile net income to net cash provided by operating activities (excluding depreciation and amortization)	48,203	(199,738)	(79,060)
EBITDA	215,474	(50,666)	166,702
Termination Fee	11,579	—	—
Impairment charges	—	236,377	—
Adjusted EBITDA	$227,053	$185,711	$166,702
Net cash used in investing activities	$(157,153)	$(100,790)	$(341,002)
Net cash provided by financing activities	$61,119	$(21,939)	$225,339

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 $176.0 million in capital expenditures for construction of new projects and enhancement of our existing power plants, of which we have invested approximately $37.0 million as of December 31, 2013 and of which we expect to invest $130.0 million in 2014 and the remaining $10.0 million thereafter.

In addition, we estimate approximately $99.0 million in additional capital expenditures in 2014 to be allocated as follows: (i) $45.0 million in development of new projects; (ii) $21.0 million for maintenance capital expenditures of our operating power plants; (iii) $28.0 million in exploration activities in various leases for geothermal resources in which we have started the exploration activity; and (iv) $5.0 million in enhancement of our production facilities.

In the aggregate, we estimate our total capital expenditures for 2014 to be approximately $229.0 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 September and October 2013, we entered into derivative transactions to reduce our exposure to the price of natural gas, under these PPAs, until December 31, 2014. The Puna complex is currently benefiting from energy prices which are higher than the floor under the 25 MW PPA for the Puna complex as a result of the high fuel costs that impact HELCO's avoided costs. Likewise, in October 2013 we entered into derivative transactions 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, 2013, 86.3% 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, 13.7% 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, 2013, $147.8 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, 2013 and 2012 by a hypothetical 10% and calculating the resulting change in the fair values.

The results of the sensitivity analysis calculations as of December 31, 2013 and 2012 are presented below:

Risk	Assuming a 10% Increase in Rates As of December 31, 2013	2012	Assuming a 10% Decrease in Rates As of December 31, 2013	2012	Change in the Fair Value of
	(In thousands)				
NGI Price	$(3,522)	$(484)	$3,522	$6,097	NGI Swap
NYMEX Heating Oil Price	(3,442)	(439)	3,442	1,037	NYMEX HO2 Swap
ICE Brent Price	-	(122)	-	41	ICE Brent Swap
NYMEX Heating Oil Price	-	790	-	2,988	NYMEX HO2 Fixed Rate Put
ICE Brent Price	-	135	-	429	ICE Brent Fixed Rate Put
Foreign Currency	(3,381)	(5,074)	4,133	7,503	Foreign Currency Forward Contracts
Interest Rate	(2,562)	(3,388)	2,690	3,557	Ormat Funding Corp. ("OFC")
Interest Rate	(1,298)	(1,550)	1,339	1,650	Orcal Geothermal Inc. ("OrCal")
Interest Rate	(5,519)	(5,600)	5,962	6,100	OFC 2 LLC ("OFC 2")
Interest Rate	(379)	(540)	388	560	Loan from DEG
Interest Rate	(11,836)	-	12,683	-	Loan from OPIC
Interest Rate	(328)	(532)	333	468	Loan from TCW
Interest Rate	(4,349)	(5,477)	4,438	5,623	Senior unsecured bonds
Interest Rate	-	(401)	-	99	Loan from institutional investors

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, 2013 (in thousands):

	Payments Due By Period						
	Remaining Total	**2014**	**2015**	**2016**	**2017**	**2018**	**Thereafter**
Long-term liabilities principal	$1,077,857	$80,389	$74,386	$201,621	$311,890	$53,954	$ 355,617
Interest on long-term liabilities [1]	360,538	64,091	59,103	51,687	44,949	23,555	117,153
Future minimum operating lease	55,866	8,647	8,222	8,374	8,747	8,944	12,932
Benefits upon retirement [2]	18,426	4,791	232	1,258	2,517	2,027	7,601
Asset retirement obligation	18,679	—	—	—	—	—	18,679
Purchase commitments [3]	37,300	57,300	—	—	—	—	—
	$1,588,666	$215,218	$141,943	$262,940	$368,103	$88,480	$ 511,982

(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 $27.1 million as of December 31, 2013, at a rate of 6.9% and variable on the remaining balance (which as of December 31, 2013 was $12.4 million). Interest on the Amatitlan Loan due in 2016 is fixed at a rate of 9.83%. 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, 2013, total obligations related to such supplier agreements were approximately $57.3 million (approximately $26.6.million of which relate to construction-in-process). All such obligations are payable in 2014.

The above table does not reflect unrecognized tax benefits of $5.0 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 $61.0 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.

Sierra Pacific Power Company and Nevada Power Company accounted for 17.6%, 15.7%, and 13.3% of our total revenues for the three years ended December 31, 2013, 2012, and 2011, respectively.

Southern California Edison accounted for 14.2%, 18.0%, and 28.5% of our total revenues for the three years ended December 31, 2013, 2012, and 2011, respectively.

KPLC accounted for 11.6%, 8.1%, and 8.3% of our total revenues for the three years ended December 31, 2013, 2012, and 2011, respectively.

HELCO accounted for 9.2%, 9.7%, and 10.9% of our total revenues for the three years ended December 31, 2013, 2012, and 2011, 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, 2013, 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.

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, 2013 and 2012, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2013 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, 2013, based on criteria established in *Internal Control — Integrated Framework (1992)* 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 28, 2014

ORMAT TECHNOLOGIES, INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

	December 31, 2013	2012 As Revised
	(Dollars in thousands)	
ASSETS		
Current assets:		
Cash and cash equivalents	$57,354	$66,628
Short-term bank deposit	—	3,010
Restricted cash and cash equivalents (all related to VIEs)	51,065	76,537
Receivables:		
Trade	95,365	55,680
Related entity	442	373
Other	11,049	8,632
Due from Parent	382	311
Inventories	22,289	20,669
Costs and estimated earnings in excess of billings on uncompleted contracts	21,217	9,613
Deferred income taxes	523	637
Prepaid expenses and other	29,654	34,144
Total current assets	289,340	276,234
Unconsolidated investments	7,076	2,591
Deposits and other	22,114	36,187
Deferred income taxes	891	21,283
Deferred charges	36,738	35,351
Property, plant and equipment, net ($1,381,083 and $1,188,721 related to VIEs, respectively)	1,452,336	1,252,873
Construction-in-process ($136,947 and $253,775 related to VIEs, respectively)	288,827	396,141
Deferred financing and lease costs, net	30,178	31,371
Intangible assets, net	31,933	35,492
Total assets	$2,159,433	$2,087,523
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable and accrued expenses	$98,047	$98,001
Deferred income taxes	—	20,392
Billings in excess of costs and estimated earnings on uncompleted contracts	7,903	25,408
Current portion of long-term debt:		
Limited and non-recourse (all related to VIEs):		
Senior secured notes	31,137	28,231
Other loans	20,377	11,453

Full recourse:	28,875	28,649
Total current liabilities	186,339	212,134
Long-term debt, net of current portion:		
Limited and non-recourse (all related to VIEs):		
Senior secured notes	270,310	312,926
Other loans	311,078	242,815
Full recourse:		
Senior unsecured bonds (plus unamortized premium based upon 7% of $1,128)	250,596	250,904
Other loans	53,467	82,344
Revolving credit lines with banks	112,017	73,606
Liability associated with sale of tax benefits	60,985	51,126
Deferred lease income	63,496	66,398
Deferred income taxes	55,035	45,059
Liability for unrecognized tax benefits	4,950	7,280
Liabilities for severance pay	23,841	22,887
Asset retirement obligation	18,679	19,289
Other long-term liabilities	3,529	5,148
Total liabilities	1,414,322	1,391,916
Commitments and contingencies (Note 22)		
Equity:		
The Company's stockholders' equity:		
Common stock, par value $0.001 per share; 200,000,000 shares authorized; 45,460,653 and 45,430,886 shares issued and outstanding as of December 31, 2013 and 2012, respectively	46	46
Additional paid-in capital	735,295	732,140
Accumulated deficit	(3,088)	(44,326)
Accumulated other comprehensive income	487	651
	732,740	688,511
Noncontrolling interest	12,371	7,096
Total equity	745,111	695,607
Total liabilities and equity	$2,159,433	$2,087,523

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,		
	2013	2012 As Revised	2011
	(Dollars in thousands, except per share data)		
Revenues:			
Electricity	$329,747	$314,894	$312,296
Product	203,492	186,879	113,160
Total revenues	533,239	501,773	425,456
Cost of revenues:			
Electricity	232,874	237,415	235,609
Product	140,547	135,346	76,072
Total cost of revenues	373,421	372,761	311,681
Gross margin	159,818	129,012	113,775
Operating expenses:			
Research and development expenses	4,965	6,108	8,801
Selling and marketing expenses	24,613	15,718	16,053
General and administrative expenses	29,188	28,066	27,366
Impairment charges	—	236,377	—
Write-off of unsuccessful exploration activities	4,094	2,639	—
Operating income (loss)	96,958	(159,896)	61,555
Other income (expense):			
Interest income	1,332	1,201	1,427
Interest expense, net	(73,776)	(64,069)	(69,459)
Foreign currency translation and transaction gains (losses)	5,085	242	(1,350)
Income attributable to sale of tax benefits	19,945	10,127	11,474
Other non-operating income, net	1,592	590	671
Income (loss) from continuing operations, before income taxes and equity in losses of investees	51,136	(211,805)	4,318
Income tax provision	(13,552)	(1,827)	(48,240)
Equity in losses of investees, net	(250)	(2,522)	(959)
Income (loss) from continuing operations	37,334	(216,154)	(44,881)
Discontinued operations:			
Income from discontinued operations (including gain on disposal of $3,646, $0 and $0, respectively)	5,311	4,811	2,452
Income tax provision	(614)	(1,264)	(295)
Total income from discontinued operations	4,697	3,547	2,157

Net income (loss)	42,031	(212,607)	(42,724)
Net income attributable to noncontrolling interest	(793)	(414)	(332)
Net income (loss) attributable to the Company's stockholders	$41,238	$(213,021)	$(43,056)
Comprehensive income (loss):			
Net income (loss)	42,031	(212,607)	(42,724)
Other comprehensive income (loss), net of related taxes:			
Amortization of unrealized gains in respect of derivative instruments designated for cash flow hedge	(164)	(190)	(212)
Change in unrealized gains or losses on marketable securities available-for-sale	—	246	(237)
Comprehensive income (loss)	41,867	(212,551)	(43,173)
Comprehensive income attributable to noncontrolling interest	(793)	(414)	(332)
Comprehensive income (loss) attributable to the Company's stockholders	$41,074	$(212,965)	$(43,505)
Earnings (loss) per share attributable to the Company's stockholders:			
Basic:			
Income (loss) from continuing operations	$0.81	$(4.77)	$(1.00)
Discontinued operations	0.10	0.08	0.05
Net income (loss)	$0.91	$(4.69)	$(0.95)
Diluted:			
Income (loss) from continuing operations	$0.81	$(4.77)	$(1.00)
Discontinued operations	0.10	0.08	0.05
Net income (loss)	$0.91	$(4.69)	$(0.95)
Weighted average number of shares used in computation of earnings (loss) per share attributable to the Company's stockholders:			
Basic	45,440	45,431	45,431
Diluted	45,475	45,431	45,431
Dividend per share declared	$0.08	$0.08	$0.13

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							
	Common Stock		Additional Paid-in	Retained Earnings (Accumulated	Accumulated Other Comprehensive		Noncontrolling	Total
	Shares	Amount	Capital	Deficit)	Income	Total	Interest	Equity
	(Dollars in thousands, except per share data)							
Balance at December 31, 2010	45,431	$ 46	$716,731	$ 221,311	$ 1,044	$939,132	$ 6,095	$945,227
Stock-based compensation	—	—	6,672	—	—	6,672	—	6,672
Increase in noncontrolling interest due to sale of equity interest in OPC LLC	—	—	2,343	—	—	2,343	1,499	3,842
Cash dividend paid, $0.13 per share	—	—	—	(5,924)	—	(5,924)	—	(5,924)
Net (loss) income	—	—	—	(43,056)	—	(43,056)	332	(42,724)
Other comprehensive income (loss), net of related taxes:								
Amortization of gains in respect of derivative instruments designated for cash flow hedge (net of related tax of $130)	—	—	—	—	(212)	(212)	—	(212)
Change in fair value of marketable securities available-for-sale (net of related tax of $0)	—	—	—	—	(237)	(237)	—	(237)
Balance at December 31, 2011	45,431	46	725,746	172,331	595	898,718	7,926	906,644
Stock-based compensation	—	—	6,394	—	—	6,394	—	6,394
Cash paid to noncontrolling interest	—	—	—	—	—	—	(1,244)	(1,244)
Cash dividend paid, $0.08 per share	—	—	—	(3,636)	—	(3,636)	—	(3,636)
Net (loss) income, as revised	—	—	—	(213,021)	—	(213,021)	414	(212,607)

Other comprehensive income (loss), net of related taxes:								
Amortization of gains in respect of derivative instruments designated for cash flow hedge (net of related tax of $117)	—	—	—	—	(190)	(190)	—	(190)
Change in fair value of marketable securities available-for-sale (net of related tax of $0)	—	—	—	—	246	246	—	246
Balance at December 31, 2012, as revised	45,431	46	732,140	(44,326)	651	688,511	7,096	695,607
Stock-based compensation	—	—	6,262	—	—	6,262	—	6,262
Exercise of options by employees and directors	30	—	529	—	—	529	—	529
Cash paid to noncontrolling interest	—	—	—	—	—	—	(669)	(669)
Cash dividend paid, $0.08 per share	—	—	(3,636)	—	—	(3,636)	—	(3,636)
Increase in noncontrolling interest in ORTP LLC	—	—	—	—	—	—	5,151	5,151
Net income	—	—	—	41,238	—	41,238	793	42,031
Other comprehensive income (loss), net of related taxes:								
Amortization of gains in respect of derivative instruments designated for cash flow hedge (net of related tax of $101)	—	—	—	—	(164)	(164)	—	(164)
Balance at December 31, 2013	45,461	$ 46	$ 735,295	$ (3,088)	$ 487	$ 732,740	$ 12,371	$ 745,111

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

ORMAT TECHNOLOGIES, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2013	2012 As Revised	2011
	(Dollars in thousands)		
Cash flows from operating activities:			
Net income (loss)	$42,031	$(212,607)	$(42,724)
Adjustments to reconcile net income or loss to net cash provided by operating activities:			
Depreciation and amortization	92,932	102,340	96,398
Amortization of premium from senior unsecured bonds	(307)	(307)	(256)
Accretion of asset retirement obligation	1,544	1,701	1,593
Stock-based compensation	6,262	6,394	6,672
Amortization of deferred lease income	(2,685)	(2,685)	(2,685)
Income attributable to sale of tax benefits, net of interest expense	(7,999)	(4,003)	(4,315)
Equity in income (losses) of investees	150	442	959
Mark-to-market of derivative instruments	7,813	—	—
Impairment of auction rate securities	—	—	205
Write-off of unconsolidated investment	—	2,114	—
Write-off of unsuccessful exploration activities	4,039	2,639	—
Impairment charge	—	236,377	—
Loss (gain) on severance pay fund asset	(877)	(931)	588
Premium from issuance of senior unsecured bonds	—	—	1,957
Gain on sale of a subsidiary	(3,646)	—	—
Deferred income tax provision (benefit)	9,245	(4,736)	38,061
Liability for unrecognized tax benefits	(2,330)	1,405	444
Deferred lease revenues	(217)	128	376
Gain on repurchase of OFC bonds	(819)	—	—
Changes in operating assets and liabilities, net of amounts acquired:			
Receivables	(37,174)	(3,623)	1,979
Costs and estimated earnings in excess of billings on uncompleted contracts	(11,604)	(5,647)	2,180
Inventories	(1,620)	(8,128)	(3)
Prepaid expenses and other	(600)	(15,472)	(3,743)
Deposits and other	621	(12,746)	(710)
Accounts payable and accrued expenses	6,077	11,414	6,646
Due from/to related entities, net	(69)	(86)	16
Billings in excess of costs and estimated earnings on uncompleted contracts	(17,505)	(7,696)	29,951
Liabilities for severance pay	1,267	2,340	(159)
Other long-term liabilities	2,302	895	(708)
Due from/to Parent	(71)	(51)	12

Net cash provided by operating activities	86,760	89,471	132,734
Cash flows from investing activities:			
Marketable securities, net	—	18,763	(17,534)
Short-term deposit	3,010	(3,010)	—
Net change in restricted cash, cash equivalents and marketable securities	25,472	(1,016)	(50,614)
Cash received from sale of a subsidiary	7,699	—	—
Capital expenditures	(204,628)	(233,020)	(269,677)
Cash grant received	14,685	119,199	—
Investment in unconsolidated companies	(4,635)	(1,390)	(472)
Cash paid for investment in a joint venture	—	—	(200)
Intangible assets acquired	—	—	(1,786)
Decrease in severance pay fund asset, net of payments made to retired employees	1,244	(316)	(719)
Net cash used in investing activities	(157,153)	(100,790)	(341,002)
Cash flows from financing activities:			
Proceeds from issuance of senior unsecured bonds	—	1,171	107,447
Proceeds from long-term loans, net of transaction costs	90,000	214,051	—
Proceeds from exercise of options by employees	529	—	—
Proceeds from issuance of senior secured notes, net of transaction costs	—	—	141,108
Proceeds from the sale of limited liability company interest in OPC LLC, net of transaction costs	—	—	24,878
Proceeds from the sale of limited liability company interest in ORTP LLC, net of transaction costs	31,376	—	—
Purchase of OFC Senior Secured Notes	(11,888)	—	—
Proceeds from revolving credit lines with banks	3,058,956	2,953,535	891,583
Repayment of revolving credit lines with banks	(3,020,545)	(3,093,978)	(867,000)
Repayments of long-term debt	(68,370)	(74,502)	(50,130)
Cash paid to non-controlling interest	(13,384)	(15,383)	(14,039)
Deferred debt issuance costs	(1,919)	(3,197)	(2,584)
Cash dividends paid	(3,636)	(3,636)	(5,924)
Net cash provided by (used in) financing activities	61,119	(21,939)	225,339
Net change in cash and cash equivalents	(9,274)	(33,258)	17,071
Cash and cash equivalents at beginning of year	66,628	99,886	82,815
Cash and cash equivalents at end of year	$57,354	$66,628	$99,886
Supplemental disclosure of cash flow information:			
Cash paid during the year for:			
Interest, net of interest capitalized	$51,306	$40,398	$33,274
Income taxes, net	$4,114	$11,570	$13,575
Supplemental non-cash investing and financing activities:			
Increase (decrease) in accounts payable related to purchases of property, plant and equipment	$4,372	$(18,813)	$13,117
Increase (decrease) in asset retirement cost and asset retirement obligation	$588	$(3,696)	$(212)

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

ORMAT TECHNOLOGIES, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1 — BUSINESS AND SIGNIFICANT ACCOUNTING POLICIES

Business

Ormat Technologies, Inc. (the “Company”), a subsidiary of Ormat Industries Ltd. (the “Parent”), is primarily engaged in the geothermal and recovered energy business, including the supply of equipment that is manufactured by the Company and the design and construction of power plants for projects owned by the Company or for third parties. The Company owns and operates geothermal and recovered energy-based power plants in various countries, including the United States of America (“U.S.”), Kenya, and Guatemala. The Company’s equipment manufacturing operations are located in Israel.

Most of the Company’s domestic power plant facilities are Qualifying Facilities under the Public Utility Regulatory Policies Act of 1978 (“PURPA”). The power purchase agreements (“PPAs”) for certain of such facilities are dependent upon their maintaining Qualifying Facility status. Management believes that all of the facilities located in the U.S. were in compliance with Qualifying Facility status requirements as of December 31, 2013.

Revision of previously issued financial statements

The Company identified an error in the second quarter of 2013 related to the calculation and presentation of the income tax provision and the related deferred tax asset for the year ended December 31, 2012 and the three months ended March 31, 2013, which was a direct result of the deferred tax effects of the non-cash asset impairment charge recorded in the fourth quarter of 2012. The Company understated the valuation allowance against the U.S. deferred tax assets by $32.7 million and an additional $3.1 million at December 31, 2012 and March 31, 2013, respectively. As a result, for the year ended December 31, 2012 the Company revised the valuation allowance by $32.7 million, of which $26.1 million was recorded against property, plant and equipment where the Company recognized the deferred tax effects of grants received during 2012 and the remaining $6.6 million to the income tax provision. For the three months ended March 31, 2013, the Company revised the valuation allowance by an additional $3.1 million which also increased the tax provision for the period by the same amount.

The Company assessed the materiality of this error in accordance with the SEC's Staff Accounting Bulletin 99 and concluded that the previously issued financial statements were not materially misstated. However, if the entire correction of the error was recorded during the second quarter of fiscal 2013, the impact would be significant to the quarter ended June 30, 2013. In accordance with the SEC's Staff Accounting Bulletin 108, the Company corrected these errors by revising the affected financial statements previously included in the Company's 2012 Annual Report on Form 10-K and March 31, 2013 Quarterly Report on Form 10-Q.

This revision had no impact on the Company's revenues, gross margin, operating income (loss), income (loss) before taxes and equity income (loss) of investees. There was also no impact on the Company's consolidated net operating, investing or financing cash flows; however, the revisions impacted line items within the balance sheet at December 31, 2012 and March 31, 2013 and cash flows from operating activities for the year ended December 31, 2012 and the three months ended March 31, 2013. The revision impacted the Company income tax benefit (provision), net income (loss) from continuing operations, net income (loss) attributable to the Company's stockholders, comprehensive income (loss) and earnings (loss) per share ("EPS") in the consolidated statements of operations and comprehensive income (loss) for the year ended December 31, 2012 and the three months ended March 31, 2013.

The consolidated statement of operations and comprehensive income (loss), consolidated balance sheet, and consolidated statement of cash flows for the year ended December 31, 2012 has been revised in this Annual Report on Form 10-K, and for the three months ended March 31, 2013 will be revised to correct the errors described above prospectively in the quarterly report on Form 10-Q for the first quarter of 2014.

ORMAT TECHNOLOGIES, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The effect of the revision on the line items within the Company’s consolidated balance sheet as of December 31, 2012 is as follows:

	As of December 31, 2012		
	As reported	Adjustment	As revised
	(Dollars in thousands)		
Deferred income taxes	$53,989	$ (32,706)	$21,283
Property, plant and equipment, net	1,226,758	26,115	1,252,873
Total assets	2,094,114	(6,591)	2,087,523
Accumulated deficit	(37,735)	(6,591)	(44,326)
Total equity	702,189	(6,591)	695,607
Total liabilities and equity	2,094,114	(6,591)	2,087,523

The effect of the revision on the line items within the Company’s consolidated statements of operations and comprehensive income (loss) for the year ended December 31, 2012 is as follows:

	Year Ended December 31, 2012		
	As reported	Adjustment	As revised
	(Dollars in thousands, except per share data)		
Income tax benefit (provision)	$3,500	$ (6,591)	$(3,091)
Loss from continuing operations	(206,016)	(6,591)	(212,607)
Net loss	(206,016)	(6,591)	(212,607)
Net loss attributable to the Company's stockholders	$(206,430)	$ (6,591)	$(213,021)
Comprehensive loss	(205,960)	(6,591)	(212,551)
Comprehensive loss attributable to the Company's stockholders	$(206,374)	$ (6,591)	$(212,965)
Loss per share attributable to the Company's stockholders:			
Basic and diluted	$(4.54)	$ (0.15)	$(4.69)

The effect of the revision on the line items within the Company's consolidated statements of cash flows for the year ended December 31, 2012 is as follows:

	Year Ended December 31, 2012		
	As reported	**Adjustment**	**As revised**
	(Dollars in thousands)		
Cash flows from operating activities:			
Net loss	$(206,016)	$ (6,591)	$(212,607)
Deferred income tax provision (benefit)	(11,327)	6,591	(4,736)
Net cash provided by operating activities	$89,471	$ -	$89,471

ORMAT TECHNOLOGIES, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The effect of the revision on the line items within the Company's consolidated balance sheet as of March 31, 2013 is as follows:

	As of March 31, 2013		
	As reported	Adjustment	As revised
	(Dollars in thousands)		
Deferred income taxes	$52,939	$ (35,758)	$17,181
Property, plant and equipment, net	1,207,410	26,115	1,233,525
Total assets	2,143,568	(9,643)	2,133,925
Accumulated deficit	(39,717)	(9,643)	(49,360)
Total equity	706,519	(9,643)	696,876
Total liabilities and equity	2,143,568	(9,643)	2,133,925

The effect of the revision on the line items within the Company's consolidated statements of operations and comprehensive income (loss) for the three months ended March 31, 2013 is as follows:

	Three Months Ended March 31, 2013		
	As reported	Adjustment	As revised
	(Dollars in thousands)		
Income tax benefit (provision)	$(1,217)	$ (3,052)	$(4,269)
Loss from continuing operations	(1,897)	(3,052)	(4,949)
Net loss	(1,897)	(3,052)	(4,949)
Net loss attributable to the Company's stockholders	$(1,982)	$ (3,052)	$(5,034)
Comprehensive loss:			
Net loss	(1,897)	(3,052)	(4,949)
Comprehensive loss	(1,939)	(3,052)	(4,991)
Comprehensive loss attributable to the Company's stockholders	$2,024	$ (3,052)	$(5,076)
Loss per share attributable to the Company's stockholders:			
Basic and diluted	$(0.04)	$ (0.07)	$(0.11)

The effect of the revision on the line items within the Company's consolidated statements of cash flows for the three months ended March 31, 2013 is as follows:

	Three Months Ended March 31, 2013		
	As reported	**Adjustment**	**As revised**
	(Dollars in thousands)		
Cash flows from operating activities:			
Net loss	$(1,897)	$ (3,052)	$(4,949)
Deferred income tax provision	668	3,052	3,720
Net cash provided by operating activities	$18,216	$ -	$18,216

Cash dividends

During the years ended December 31, 2013, 2012, and 2011, the Company's Board of Directors declared, approved, and authorized the payment of cash dividends in the aggregate amount of $3.6 million ($0.08 per share), $3.6 million ($0.08 per share), and $5.9 million ($0.13 per share), respectively. Such dividends were paid in the years declared.

ORMAT TECHNOLOGIES, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Rounding

Dollar amounts, except per share data, in the notes to these financial statements are rounded to the closest $1,000, unless otherwise indicated.

Basis of presentation

The consolidated financial statements are prepared in accordance with accounting principles generally accepted in the United States of America (“U.S. GAAP”) and include the accounts of the Company and of all majority-owned subsidiaries in which the Company exercises control over operating and financial policies, and variable interest entities in which the Company has an interest and is the primary beneficiary. Intercompany accounts and transactions have been eliminated in consolidation.

Investments in less-than-majority-owned entities or other entities in which the Company exercises significant influence over operating and financial policies are accounted for using the equity method of accounting or consolidated if they are a variable interest entity in which the Company has an interest and is the primary beneficiary. Under the equity method, original investments are recorded at cost and adjusted by the Company’s share of undistributed earnings or losses of such companies. The Company’s earnings or losses in investments accounted for under the equity method have been reflected as “equity in income (losses) of investees, net” on the Company’s consolidated statements of operations and comprehensive income (loss).

Cash and cash equivalents

The Company considers all highly liquid instruments, with an original maturity of three months or less, to be cash equivalents.

Restricted cash, cash equivalents, and marketable securities

Under the terms of certain long-term debt agreements, the Company is required to maintain certain debt service reserves, cash collateral and operating fund accounts that have been classified as restricted cash and cash equivalents. Funds that will be used to satisfy obligations due during the next twelve months are classified as current restricted cash and cash equivalents, with the remainder classified as non-current restricted cash and cash equivalents (see Note 6). Such amounts were invested primarily in money market accounts and commercial paper with a minimum investment grade of "AA".

During the years ended December 31, 2012 and 2011, the Company had investments in marketable securities that were classified as available-for-sale. The changes in the fair value of those securities were recorded in other comprehensive income (loss).

Termination fee

Fees to terminate power purchase agreements ("PPAs") are recognized in period incurred as selling and marketing expenses. During 2013, the Company finalized the agreement with Southern California Edison Company ("Southern California Edison"), by which the G1 and G3 Standard Offer #4 PPAs were terminated and a termination fee of $9.0 million. In addition, an amount of $2.6 million was paid to NV Energy related to the termination of the Dixie Meadows PPA.

Concentration of credit risk

Financial instruments which potentially subject the Company to concentration of credit risk consist principally of temporary cash investments and accounts receivable.

ORMAT TECHNOLOGIES, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The Company places its temporary cash investments with high credit quality financial institutions located in the U.S. and in foreign countries. At December 31, 2013 and 2012, the Company had deposits totaling $13,805,000 and $41,231,000, respectively, in seven U.S. financial institutions that were federally insured up to $250,000 per account. At December 31, 2013 and 2012, the Company’s deposits in foreign countries of approximately $56,133,000 and $33,215,000, respectively, were not insured.

At December 31, 2013 and 2012, accounts receivable related to operations in foreign countries amounted to approximately $32,231,000 and $17,606,000, respectively. At December 31, 2013, and 2012, accounts receivable from the Company’s major customers (see Note 19) amounted to approximately 35% and 45%, respectively, of the Company’s accounts receivable.

The Company performs ongoing credit evaluations of its customers’ financial condition. The Company has historically been able to collect on substantially all of its receivable balances, and accordingly, no provision for doubtful accounts has been made.

Inventories

Inventories consist primarily of raw material parts and sub-assemblies for power units, and are stated at the lower of cost or market value, using the weighted-average cost method. Inventories are reduced by a provision for slow-moving and obsolete inventories. This provision was not significant at December 31, 2013 and 2012.

Deposits and other

Deposits and other consist primarily of performance bonds for construction projects, long-term insurance contract and receivables, and derivative instruments.

Deferred charges

Deferred charges represent prepaid income taxes on intercompany sales. Such amounts are amortized using the straight-line method and included in income tax provision over the life of the related property, plant and equipment.

Property, plant and equipment

Property, plant and equipment are stated at cost. All costs associated with the acquisition, development and construction of power plants operated by the Company are capitalized. Major improvements are capitalized and repairs and maintenance (including major maintenance) costs are expensed. Power plants operated by the Company, which include geothermal wells and exploration and resource development costs, are depreciated using the straight-line method over their estimated useful lives, which range from 25 to 30 years. The geothermal power plant in Zunil, Guatemala is to be fully depreciated over the term of the PPA, since the Company does not own the geothermal resource used by the plant (see Note 24). The other assets are depreciated using the straight-line method over the following estimated useful lives of the assets:

Leasehold improvements (years)	15	-	20
Machinery and equipment — manufacturing and drilling (years)	10		
Machinery and equipment — computers (years)	3	-	5
Office equipment — furniture and fixtures (years)	5	-	15
Office equipment — other (years)	5	-	10
Automobiles (years)	5	-	7

The cost and accumulated depreciation of items sold or retired are removed from the accounts. Any resulting gain or loss is recognized currently and is recorded in operating income.

The Company capitalizes interest costs as part of constructing power plant facilities. Such capitalized interest is recorded as part of the asset to which it relates and is amortized over the asset's estimated useful life. Capitalized interest costs amounted to $7,598,000, $11,964,000, and $11,709,000 for the years ended December 31, 2013, 2012, and 2011, respectively.

ORMAT TECHNOLOGIES, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Cash Grants

From time to time, the Company is awarded cash grants from the U.S. Department of the Treasury (“U.S. Treasury”) for Specified Energy Property in Lieu of Tax Credits under Section 1603 of the American Recovery and Reinvestment Act of 2009 (“ARRA”). The Company records the cash grant as a reduction in the carrying value of the related plant and amortizes the grant as a reduction in depreciation expense over the plant’s estimated useful life.

Exploration and development costs

The Company capitalizes costs incurred in connection with the exploration and development of geothermal resources once it acquires land rights to the potential geothermal resource. Prior to acquiring land rights, the Company makes an initial assessment that an economically feasible geothermal reservoir is probable on that land. The Company determines the economic feasibility of potential geothermal resources internally, with all available data and external assessments vetted through the exploration department and occasionally using outside service providers. Costs associated with the initial assessment are expensed and included in cost of electricity revenues in the consolidated statements of operations and comprehensive income (loss). Such costs were immaterial during the years ended December 31, 2013, 2012, and 2011. It normally takes two to three years from the time active exploration of a particular geothermal resource begins to the time a production well is in operation, assuming the resource is commercially viable. However, in certain sites the process may take longer due to permitting delays, transmission constraints or any other commercial milestones that are required to be reached in order to pursue the development process.

In most cases, the Company obtains the right to conduct the geothermal development and operations on land owned by the Bureau of Land Management (“BLM”), various states or with private parties. In consideration for certain of these leases, the Company may pay an up-front bonus payment which is a component of the competitive lease process. The up-front bonus payments and other related costs, such as legal fees, are capitalized and included in construction-in-process. The annual land lease payments made during the exploration, development and construction phase are expensed as incurred and included in “electricity cost of revenues” in the consolidated statements of operations and comprehensive income (loss). Upon commencement of power generation on the leased land, the Company begins to pay to the lessors long-term royalty payments based on the utilization of the geothermal resources as defined in the respective agreements. Such payments are expensed when the related revenues are earned and included in “electricity cost of revenues” in the consolidated statements of operations and comprehensive income (loss).

Following the acquisition of land rights to the potential geothermal resource, the Company conducts further studies and surveys, including water and soil analyses among others, and augments its database with the results of these studies. The Company then initiates a suite of geophysical surveys to assess the resource and determine drilling locations. If the results of these activities support the initial assessment of the feasibility of the geothermal resource, the Company then proceeds to exploratory drilling and other related activities which may include drilling of temperature gradient holes, drilling of slim holes, building access roads to drilling locations, drilling full size production and/or injection wells and flow tests. If the slim hole supports a conclusion that the geothermal resource will support a commercially viable power plant, it may be converted to a full-size commercial well, used either for extraction or re-injection or geothermal fluids, or be used as an observation well to monitor and define the geothermal resource. Costs associated with these activities and other directly attributable costs, including interest once physical exploration activities begin and permitting costs are capitalized and included in “construction-in-process”. If the Company concludes that a geothermal resource will not support commercial operations, capitalized costs are expensed in the period such determination is made.

Grants received from the U.S. Department of Energy (“DOE”) are offset against the related exploration and development costs. Such grants amounted to $1,665,000, $1,368,000, and $6,194,000 for the years ended December 31, 2013, 2012, and 2011, respectively.

All exploration and development costs that are being capitalized, including the up-front bonus payments made to secure land leases, will be depreciated over their estimated useful lives when the related geothermal power plant is substantially complete and ready for use. A geothermal power plant is substantially complete and ready for use when electricity generation commences.

ORMAT TECHNOLOGIES, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Asset retirement obligation

The Company records the fair value of a legal liability for an asset retirement obligation in the period in which it is incurred. The Company’s legal liabilities include plugging wells and post-closure costs of power producing sites. When a new liability for asset retirement obligations is recorded, the Company capitalizes the costs of the liability by increasing the carrying amount of the related long-lived asset. The 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, the obligation is settled for its recorded amount at a gain or loss.

Deferred financing and lease transaction costs

Deferred financing costs are amortized over the term of the related obligation using the effective interest method. Amortization of deferred financing costs is presented as interest expense in the consolidated statements of operations and comprehensive income (loss). Accumulated amortization related to deferred financing costs amounted to $25,371,000 and $20,209,000 at December 31, 2013 and 2012, respectively. Amortization expense for the years ended December 31, 2013, 2012, and 2011 amounted to $6,009,000, $3,676,000, and $3,567,000, respectively. In the year ended December 31, 2013 an amount of $254,000 was written-off as a result of the extinguishment of liability.

Deferred transaction costs relating to the Puna operating lease (see Note 11) in the amount of $4,172,000 are amortized using the straight-line method over the 23-year term of the lease. Amortization of deferred transaction costs is presented in cost of revenues in the consolidated statements of operations and comprehensive income (loss). Accumulated amortization related to deferred lease costs amounted to $1,589,000 and $1,405,000 at December 31, 2013 and 2012, respectively. Amortization expense for each of the years ended December 31, 2013, 2012, and 2011 amounted to $184,000.

Intangible assets

Intangible assets consist of allocated acquisition costs of PPAs, which are amortized using the straight-line method over the 13 to 25-year terms of the agreements (see Note 8).

Impairment of long-lived assets and long-lived assets to be disposed of

The Company evaluates 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 the Company’s use of assets or its 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 its business or when it concludes that it is more likely than not that an asset will be disposed of or sold.

The Company tests its 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 all of the power plants in a complex 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. The Company tests for impairment its operating plants which are not operated as a complex as well as its 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, the Company will test for impairment at the complex level.

ORMAT TECHNOLOGIES, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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 the Company uses in estimating its undiscounted future cash flows include: (i) projected generating capacity of the complex or power plant and rates to be received under the respective PPA(s)) and expected market rates thereafter and (ii) projected operating expenses of the relevant complex or 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 the assets are considered to be impaired, the impairment to be recognized is measured by 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. Management believes that no impairment exists for long-lived assets; however, estimates as to the recoverability of such assets may change based on revised circumstances. If actual cash flows differ significantly from the Company's current estimates, a material impairment charge may be required in the future.

Derivative instruments

Derivative instruments (including certain derivative instruments embedded in other contracts) are measured at their fair value and recorded as either assets or liabilities unless exempted from derivative treatment as a normal purchase and sale. All changes in the fair value of derivatives are recognized currently in earnings unless specific hedge criteria are met, which requires a company to formally document, designate and assess the effectiveness of transactions that receive hedge accounting.

The Company maintains a risk management strategy that incorporates the use of swap contracts and put options on oil and natural gas prices, forward exchange contracts, interest rate swaps, and interest rate caps to minimize significant fluctuation in cash flows and/or earnings that are caused by oil and natural gas prices, exchange rate or interest rate volatility. Gains or losses on contracts that initially qualify for cash flow hedge accounting, net of related taxes, are included as a component of other comprehensive income or loss and are subsequently reclassified into earnings when the hedged forecasted transaction affects earnings. Gains or losses on contracts that are not designated as a cash flow hedge are included currently in earnings.

Foreign currency translation

The U.S. dollar is the functional currency for all of the Company's consolidated operations and those of its equity affiliates. For those entities, all gains and losses from currency translations are included in the consolidated statements of operations and comprehensive income (loss).

Comprehensive income (loss) reporting

Comprehensive income (loss) includes net income or loss plus other comprehensive income (loss), which for the Company consists of foreign currency translation adjustments, the non-credit portion of unrealized gain or loss on available-for-sale marketable securities and the mark-to-market gains or losses on derivative instruments designated as a cash flow hedge. For the years ended December 31, 2013, 2012 and 2011, the Company reclassified ($164,000), 56,000 and ($449,000), respectively, from other comprehensive income, of which $265,000, 61,000 and $579,000, respectively, were recorded to reduce interest expense and $101,000, 117,000 and $130,000, respectively, were recorded against the income tax provision, in the consolidated statements of operations and comprehensive income (loss).

Revenues and cost of revenues

Revenues are primarily related to: (i) sale of electricity from geothermal and recovered energy-based power plants owned and operated by the Company and (ii) geothermal and recovered energy-based power plant equipment engineering, sale, construction and installation, and operating services.

ORMAT TECHNOLOGIES, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Revenues related to the sale of electricity from geothermal and recovered energy-based power plants and capacity payments are recorded based upon output delivered and capacity provided at rates specified under relevant contract terms. For PPAs agreed to, modified, or acquired in business combinations on or after July 1, 2003, the Company determines whether such PPAs contain a lease element requiring lease accounting. Revenue from such PPAs are accounted for in electricity revenues. The lease element of the PPAs is also assessed in accordance with the revenue arrangements with multiple deliverables guidance, which requires that revenues be allocated to the separate earnings processes based on their relative fair value. PPAs with minimum lease rentals which vary over time are generally recognized on the straight-line basis over the term of the PPAs. PPAs with contingent rentals are recognized when earned.

Revenues from engineering, operating services, and parts and product sales are recorded upon providing the service or delivery of the products and parts and when collectability is reasonably assured. Revenues from the supply and/or construction of geothermal and recovered energy-based power plant equipment and other equipment to third parties are recognized using the percentage-of-completion method. Revenue is recognized based on the percentage relationship that incurred costs bear to total estimated costs. Costs include direct material, labor, and indirect costs. Selling, marketing, general, and administrative costs are charged to expense as incurred. Provisions for estimated losses on uncompleted contracts are made in the period in which such losses are determined. Changes in job performance, job conditions, and estimated profitability, including those arising from contract penalty provisions and final contract settlements, may result in revisions to costs and revenues and are recognized in the period in which the revisions are determined.

In specific instances where there is a lack of dependable estimates or inherent risks cause forecast to be doubtful, then the completed-contract method is followed. Revenue is recognized when the contract is substantially complete and when collectability is reasonably assured. Costs that are closely associated with the project are deferred as contract costs and recognized similarly to the associated revenues.

Warranty on products sold

The Company generally provides a one-year warranty against defects in workmanship and materials related to the sale of products for electricity generation. Estimated future warranty obligations are included in operating expenses in the period in which the related revenue is recognized. Such charges are immaterial for the years ended December 31, 2013, 2012, and 2011.

Research and development

Research and development costs incurred by the Company for the development of existing and new geothermal, recovered energy and remote power technologies are expensed as incurred. Grants received from the DOE are offset against the related research and development expenses. Such grants amounted to $1,616,000, $660,000, and $1,143,000 for the years ended December 31, 2013, 2012, and 2011, respectively.

Stock-based compensation

The Company accounts for stock-based compensation using the fair value method whereby compensation cost is measured at the grant date, based on the calculated fair value of the award, and is recognized as an expense over the requisite employee service period (generally the vesting period of the grant). The Company uses the simplified method in developing an estimate of the expected term of “plain vanilla” stock-based awards.

ORMAT TECHNOLOGIES, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Income taxes

Income taxes are accounted for using the asset and liability approach, which requires the recognition of taxes payable or refundable for the current year and deferred tax assets and liabilities for the future tax consequences of events that have been recognized in the Company's financial statements or tax returns. The measurement of current and deferred tax assets and liabilities are based on provisions of the enacted tax law. The effects of future changes in tax laws or rates are not anticipated. The Company accounts for investment tax credits and production tax credits as a reduction to income taxes in the year in which the credit arises. The measurement of deferred tax assets is reduced, if necessary, by the amount of any tax benefits that, based on available evidence, are not, more likely than not expected to be realized. A full valuation allowance has been established to offset the Company's U.S. deferred tax assets. Tax benefits from uncertain tax positions are recognized only if it is more likely than not that the tax position will be sustained on examination by the taxing authorities, based on the technical merits of the position.

Earnings (losses) per share

Basic earnings (losses) per share attributable to the Company's stockholders ("earnings (losses) per share") is computed by dividing net income or loss attributable to the Company's stockholders by the weighted average number of shares of common stock outstanding for the period. The Company does not have any equity instruments that are dilutive, except for stock-based awards.

The table below shows the reconciliation of the number of shares used in the computation of basic and diluted earnings (losses) per share:

	Year Ended December 31,		
	2013	**2012**	**2011**
	(In thousands)		
Weighted average number of shares used in computation of basic earnings (losses) per share	45,440	45,431	45,431
Add:			

Additional shares from the assumed exercise of employee stock awards	35	-	-
Weighted average number of shares used in computation of diluted earnings (losses) per share	45,475	45,431	45,431

In the years ended December 31, 2012 and 2011, the employee stock options were anti-dilutive because of the Company’s net loss, and therefore, they have been excluded from the diluted earnings (losses) per share calculation.

The number of stock-based awards that could potentially dilute future earnings per share and were not included in the computation of diluted earnings (losses) per share because to do so would have been anti-dilutive was 5,139,339, 5,479,852, and 4,337,475, respectively, for the years ended December 31, 2013, 2012, and 2011.

Use of estimates in preparation of financial statements

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the dates of such financial statements and the reported amounts of revenues and expenses during the reporting periods. Actual results could differ from those estimates. The most significant estimates with regard to the Company’s consolidated financial statements relate to the useful lives of property, plant and equipment, impairment of long-lived assets and assets to be disposed of, revenue recognition of product sales using the percentage of completion method, asset retirement obligations, and the provision for income taxes.

ORMAT TECHNOLOGIES, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

New Accounting Pronouncements

New accounting pronouncements effective in the year ended December 31, 2013

Disclosures about Offsetting Assets and Liabilities

In December 2011, the Financial Accounting Standards Board ("FASB") issued accounting guidance to amend the existing disclosure requirements for offsetting financial assets and liabilities to enhance current disclosures, as well as to improve the comparability of balance sheets prepared under GAAP and those prepared under International Financial Reporting Standards. In January 2013, the FASB issued additional guidance on the scope of these disclosures. The revised disclosure guidance applies to derivative instruments and securities borrowing and lending transactions that are subject to an enforceable master netting arrangement or similar agreement. The revised disclosure guidance is effective on a retrospective basis for interim and annual periods beginning January 1, 2013. As this guidance only imposes additional disclosure requirements, its adoption did not have a material impact on the Company's consolidated financial statements.

Amounts Reclassified Out of Accumulated Other Comprehensive Income

In February 2013, the FASB updated accounting guidance to add new disclosure requirements for items reclassified out of accumulated other comprehensive income. Although the update does not change the current requirements for reporting net income or other comprehensive income in financial statements, it does require an entity to provide information about the amounts reclassified out of accumulated other comprehensive income by component. In addition, an entity is required to present, either on the face of the statement where net income is presented or in the notes thereto, significant amounts reclassified out of accumulated other comprehensive income by the respective line items of net income, but only if the amount reclassified is required to be reclassified to net income in its entirety in the same reporting period. For other amounts that are not required to be reclassified in their entirety to net income, an entity is required to cross-reference to other disclosures that provide additional detail about those amounts. The amendments included in this guidance are required to be applied on a retrospective basis for interim and annual periods beginning January 1, 2013. As this guidance only imposes additional disclosure requirements, its adoption did not have a material impact on the Company's consolidated financial statements.

Presentation of Unrecognized Tax Benefits

In July 2013, the FASB clarified the accounting guidance on presentation of the unrecognized tax benefits when a net operating loss carryforward, a similar tax loss, or a tax credit carryforward exists. The guidance states that an unrecognized tax benefit (or a portion thereof) should be presented in the financial statements as a reduction to a deferred tax asset for a net operating loss carryforward, a similar tax loss, or a tax credit carryforward, except for certain exceptions specified in the guidance. The exceptions include when a net operating loss carryforward, a similar tax loss, or a tax credit carryforward is not available at the reporting date under the tax law of the applicable jurisdiction to reduce any income taxes that would result from the disallowance of a tax position or the tax law of the applicable jurisdiction does not require the entity to use, and the entity does not intend to use, the deferred tax asset for such purpose, the unrecognized tax benefit should be presented in the financial statements as a liability and not be combined with deferred tax assets. The assessment of whether a deferred tax asset is available is based on the unrecognized tax benefit and deferred tax asset that exist at the reporting date and is to be made assuming the disallowance of the tax position at the reporting date. This accounting update is effective for fiscal periods after December 15, 2013. The provision is to be applied prospectively to all unrecognized tax benefits that exist at the effective date, and can be applied retroactively. The Company is currently evaluating the potential impact, if any, of the adoption of this guidance on its consolidated financial statements.

ORMAT TECHNOLOGIES, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 2 — INVENTORIES

Inventories consist of the following:

	December 31,	
	2013	2012
	(Dollars in thousands)	
Raw materials and purchased parts for assembly	$6,326	$9,775
Self-manufactured assembly parts and finished products	15,963	10,894
Total	$22,289	$20,669

NOTE 3 — COST AND ESTIMATED EARNINGS ON UNCOMPLETED CONTRACTS

Cost and estimated earnings on uncompleted contracts consist of the following:

	December 31,	
	2013	2012
	(Dollars in thousands)	
Costs and estimated earnings incurred on uncompleted contracts	$51,550	$192,948
Less billings to date	(38,236)	(208,743)
Total	$13,314	$(15,795)

These amounts are included in the consolidated balance sheets under the following captions:

	December 31,	
	2013	2012

	(Dollars in thousands)	
Costs and estimated earnings in excess of billings on uncompleted contracts	$21,217	$9,613
Billings in excess of costs and estimated earnings on uncompleted contracts	(7,903)	(25,408)
Total	$13,314	$(15,795)

The completion costs of the Company's construction contracts are subject to estimation. Due to uncertainties inherent in the estimation process, it is reasonably possible that estimated contract earnings will be further revised in the near term.

139

ORMAT TECHNOLOGIES, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 4 — UNCONSOLIDATED INVESTMENTS

Unconsolidated investments, mainly in power plants, consist of the following:

	December 31, 2013	December 31, 2012
	(Dollars in thousands)	
Sarulla	$7,076	$2,591

The Sarulla Project

The Company is a 12.75% member of a consortium which is in the process of developing the Sarulla geothermal power project in Indonesia with expected generating capacity of approximately 330 megawatts (“MW”). The Sarulla project is located in Tapanuli Utara, North Sumatra, Indonesia and will be owned and operated by the consortium members under the framework of a Joint Operating Contract (“JOC”) and Energy Sales Contract (“ESC”) that were signed on April 4, 2013. 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 its equity holdings in the consortium, the Company designed the Sarulla plant and is expected to supply its Ormat Energy Converters (“OECs”) to the power plant. The supply contract was signed in October 2013.

The consortium has started preliminary testing and development activities at the site and signed an engineering procurement and construction agreement (“EPC”) with an unrelated third party. The project will be constructed in three phases of 110 MW each, utilizing both steam and brine extracted from the geothermal field to increase the power plant’s efficiency. Construction is expected to begin after the consortium obtains financing, which is expected to occur in the first half of 2014. The first phase is scheduled to commence operation in 2016, and the remaining two phases are scheduled to be completed in stages within 18 months thereafter.

During 2013, the Company made additional investment contributions of $4.6 million to the Sarulla project that were consistent with the consortium ownership structure.

The Company’s share in the results of operations of the Sarulla project was not significant for each of the years presented in these consolidated financial statements.

NOTE 5 — VARIABLE INTEREST ENTITIES

The Company’s overall methodology for evaluating transactions and relationships under the variable interest entity (“VIE”) accounting and disclosure requirements includes the following two steps: (i) determining whether the entity meets the criteria to qualify as a VIE; and (ii) determining whether the Company is the primary beneficiary of the VIE.

In performing the first step, the significant factors and judgments that the Company considers in making the determination as to whether an entity is a VIE include:

- The design of the entity, including the nature of its risks and the purpose for which the entity was created, to determine the variability that the entity was designed to create and distribute to its interest holders;
- The nature of the Company’s involvement with the entity;
- Whether control of the entity may be achieved through arrangements that do not involve voting equity;
- Whether there is sufficient equity investment at risk to finance the activities of the entity; and
- Whether parties other than the equity holders have the obligation to absorb expected losses or the right to receive residual returns.

ORMAT TECHNOLOGIES, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

If the Company identifies a VIE based on the above considerations, it then performs the second step and evaluates whether it is the primary beneficiary of the VIE by considering the following significant factors and judgments:

- Whether the Company has the power to direct the activities of the VIE that most significantly impact the entity's economic performance; and

- Whether the Company has the obligation to absorb losses of the entity that could potentially be significant to the VIE or the right to receive benefits from the entity that could potentially be significant to the VIE.

The Company's VIEs include certain of its wholly owned subsidiaries that own one or more power plants with long-term PPAs. In most cases, the PPAs require the utility to purchase substantially all of the plant's electrical output over a significant portion of its estimated useful life. Most of the VIEs have associated project financing debt that is non-recourse to the general creditors of the Company, is collateralized by substantially all of the assets of the VIE and those of its wholly owned subsidiaries (also VIEs) and is fully and unconditionally guaranteed by such subsidiaries. The Company has concluded that such entities are VIEs primarily because the entities do not have sufficient equity at risk and/or subordinated financial support is provided through the long-term PPAs. The Company has evaluated each of its VIEs to determine the primary beneficiary by considering the party that has the power to direct the most significant activities of the entity. Such activities include, among others, construction of the power plant, operations and maintenance, dispatch of electricity, financing and strategy. Except for power plants that it acquired, the Company is responsible for the construction of its power plants and generally provides operation and maintenance services. Primarily due to its involvement in these and other activities, the Company has concluded that it directs the most significant activities at each of its VIEs and, therefore, is considered the primary beneficiary. The Company performs an ongoing reassessment of the VIEs to determine the primary beneficiary and may be required to deconsolidate certain of its VIEs in the future. The Company has aggregated its consolidated VIEs into the following categories: (i) wholly owned subsidiaries with project debt; (ii) wholly owned subsidiaries with PPAs; and (iii) less than majority-owned subsidiaries.

The tables below detail the assets and liabilities (excluding intercompany balances which are eliminated in consolidation) for the Company's VIEs, combined by VIE classifications, that were included in the consolidated balance sheets as of December 31, 2013 and 2012:

December 31, 2013

	Project Debt	PPAs	Less than Marjority-owned Subsidiary
	(Dollars in thousands)		
Assets:			
Restricted cash and cash equivalents	$48,276	$—	$ —
Other current assets	66,671	5,459	—
Property, plant and equipment, net	1,190,467	190,616	—
Construction-in-process	136,486	461	11,055
Other long-term assets	56,601	267	—
Total assets	$1,498,501	$196,803	$ 11,055
Liabilities:			
Accounts payable and accrued expenses	$16,087	$2,608	$ —
Long-term debt	632,906	—	—
Other long-term liabilities	103,538	5,948	—
Total liabilities	$752,531	$8,556	$ —

ORMAT TECHNOLOGIES, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

	December 31, 2012 As Revised		
	Project Debt	PPAs	Less Than Majority-Owned Subsidiary
	(Dollars in thousands)		
Assets:			
Restricted cash and cash equivalents	$76,537	$—	$ —
Other current assets	73,135	8,766	—
Property, plant and equipment, net	992,548	196,173	—
Construction-in-process	248,890	4,885	11,121
Other long-term assets	57,337	273	—
Total assets	$1,448,447	$210,097	$ 11,121
Liabilities:			
Accounts payable and accrued expenses	$25,477	$5,393	$ —
Billings in excess of costs and estimated earnings on uncompleted contracts	1,718	—	—
Long-term debt	595,425	—	—
Other long-term liabilities	81,070	8,386	—
Total liabilities	$703,690	$13,779	$ —

NOTE 6 — FAIR VALUE OF FINANCIAL INSTRUMENTS

The fair value measurement guidance clarifies that fair value is an exit price, representing the amount that would be received upon selling an asset or paid upon transferring a liability in an orderly transaction between market participants. As such, fair value is a market-based measurement that should be determined based on assumptions that market participants would use in pricing an asset or liability. The guidance establishes a fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurements) and the lowest priority to unobservable inputs (Level 3 measurements). The three levels of the fair value hierarchy under the fair value measurement guidance are described below:

Level 1 — Unadjusted quoted prices in active markets that are accessible at the measurement date for identical assets or liabilities;

Level 2 — Quoted prices in markets that are not active, or inputs that are observable, either directly or indirectly, for substantially the full term of the asset or liability;

Level 3 — Prices or valuation techniques that require inputs that are both significant to the fair value measurement and unobservable (supported by little or no market activity).

The following table sets forth certain fair value information at December 31, 2013 and 2012 for financial assets and liabilities measured at fair value by level within the fair value hierarchy, as well as cost or amortized cost. As required by the fair value measurement guidance, assets and liabilities are classified in their entirety based on the lowest level of inputs that is significant to the fair value measurement.

ORMAT TECHNOLOGIES, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

	Carrying Value at December 31, 2013	December 31, 2013 Fair Value Total	Level 1	Level 2	Level 3
		(Dollars in thousands)			
Assets					
Current assets:					
Cash equivalents (including restricted cash accounts)	$ 40,015	$40,015	$40,015	$-	$ -
Derivatives:					
Currency forward contracts[4]	2,290	2,290	-	2,290	-
Liabilities					
Current liabilities:					
Derivatives:					
Swap transaction on oil price[2]	(2,490)	(2,490)	-	(2,490)	-
Swap transaction on natural gas price[3]	(341)	(341)	-	(341)	-
	$ 39,474	$39,474	$40,015	$(541)	$ -

	Carrying Value at December 31, 2012	December 31, 2012 Fair Value Total	Level 1	Level 2	Level 3
		(Dollars in thousands)			
Assets					
Current assets:					
Cash equivalents (including restricted cash accounts)	$ 54,298	$54,298	$54,298	$-	$ -
Derivatives:					
Put options on oil price[1]	1,842	1,842	-	1,842	-
Swap transaction on oil price[2]	336	336	-	336	-
Swap transaction on natural gas price[3]	2,804	2,804	-	2,804	-
Currency forward contracts[4]	1,675	1,675	-	1,675	-
	$ 60,955	$60,955	$54,298	$6,657	$ -

(1) This amount relates to derivatives which represent European put transactions on oil prices, valued primarily based on observable inputs, including forward and spot prices for related commodity indices, and are included within “prepaid expenses and other” in the consolidated balance sheet with the corresponding gain or loss being recognized within “electricity revenues” in the consolidated statement of operations and comprehensive income (loss).

(2) This amount relates to derivatives which represent swap contract on oil prices, valued primarily based on observable inputs, including forward and spot prices for related commodity indices, and are included within “accounts payable and accrued expenses” and “prepaid expenses and other” on December 31, 2013 and 2012, respectively, in the consolidated balance sheets with the corresponding gain or loss being recognized within “electricity revenues” in the consolidated statement of operations and comprehensive income (loss).

143

ORMAT TECHNOLOGIES, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(3) This amount relates to derivatives which represent swap contract on natural gas prices, valued primarily based on observable inputs, including forward and spot prices for related commodity indices, and are included within "accounts payable and accrued expenses" and "prepaid expenses and other" on December 31, 2013 and 2012, respectively, in the consolidated balance sheets with the corresponding gain or loss being recognized within "electricity revenue" in the consolidated statement of operations and comprehensive income (loss).

(4) These amounts relate to derivatives which represent currency forward contracts valued primarily based on observable inputs, including forward and spot prices for currencies, netted against contracted rates and then multiplied against notional amounts, and are included within "prepaid expenses and other" in the consolidated balance sheet with the corresponding gain or loss being recognized within "foreign currency translation and transaction gains (losses)" in the consolidated statement of operations and comprehensive income (loss).

The Company's financial assets measured at fair value (including restricted cash accounts) at December 31, 2013 and 2012 include investments in debt instruments, money market funds (which are included in cash equivalents) and short-term bank deposits. Those securities and deposits are classified within Level 1 of the fair value hierarchy because they are valued using quoted market prices in an active market.

The following table presents the amounts of gain (loss) recognized in the consolidated statements of operations and comprehensive income (loss) on derivative instruments not designated as hedges:

Derivatives not designated as hedging instruments	**Location of recognized gain (loss)**	**Amount of recognized gain (loss)**		
		2013	**2012**	**2011**
		(Dollars in thousands)		
Put options on oil price	Electricity revenues	$(1,330)	$(807)	$ -
Put options on natural gas price	Electricity revenues	-	(1,342)	-
Swap transaction on oil price	Electricity revenues	(635)	1,598	-
Swap transactions on natural gas price	Electricity revenues	(3,052)	2,804	-
Currency forward contracts	Foreign currency translation and transaction gains	5,912	463	-
		$895	$2,716	$ -

On September 3, 2013, the Company entered into a NGI swap contract with a bank for notional volume of approximately 4.4 million MMbtus for settlement effective January 1, 2014 until December 31, 2014, in order to reduce its exposure to NGI below $4.035 per MMbtu under its PPAs with Southern California Edison. The contract did not have up-front costs. Under the terms of this contract, the Company will make floating rate payments to the bank and receive fixed rate payments from the bank on each settlement date. The swap contract has monthly settlement whereby the difference between the fixed price of $4.035 per MMbtu and the market price on the first commodity business day on which the relevant commodity reference price is published in the relevant calculation period (January 1, 2014 to December 1, 2014) will be settled on a cash basis. This contract will not be designated as hedge transaction and will be marked to market with the corresponding gains or losses recognized within “electricity revenues” in the consolidated statements of operations and comprehensive income (loss).

ORMAT TECHNOLOGIES, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

On October 16, 2013, the Company entered into a NGI swap contract with a bank for notional volume of approximately 4.2 million MMbtus for settlement effective January 1, 2014 until December 31, 2014, in order to reduce its exposure to NGI below $4.103 per MMbtu under its PPAs with Southern California Edison. The contract did not have any up-front costs. Under the terms of this contract, the Company will make floating rate payments to the bank and receive fixed rate payments from the bank on each settlement date. The swap contract has monthly settlements whereby the difference between the fixed price of $4.103 per MMbtu and the market price on the first commodity business day on which the relevant commodity reference price is published in the relevant calculation period (January 1, 2014 to December 1, 2014) will be settled on a cash basis. This contract will not be designated as a hedge transaction and will be marked to market with the corresponding gains or losses recognized within “electricity revenues” in the consolidated statements of operations and comprehensive income (loss).

On October 16, 2013, the Company entered into a New York Harbor ULSD swap contract with a bank for notional volume of 275,000 BBL effective from January 1, 2014 until December 31, 2014 to reduce the Company’s exposure to fluctuations in the energy rate caused by fluctuations in oil prices under the 25 MW PPA for the Puna complex. The Company entered into this contract because the swap had a high correlation with the avoided costs (which are incremental costs that the power purchaser avoids by not having to generate such electrical energy itself or purchase it from others) that HELCO uses to calculate the energy rate. The contract did not have any up-front costs. Under the terms of this contract, the Company will make floating rate payments to the bank and receive fixed rate payments from the bank on each settlement date ($125.15 per BBL). The swap contract has monthly settlements whereby the difference between the fixed price and the monthly average market price will be settled on a cash basis. This contract will not be designated as a hedge transaction and will be marked to market with the corresponding gains or losses recognized within “electricity revenues” in the consolidated statements of operations and comprehensive income (loss).

These transactions have not been designated as hedge transactions and are marked to market with the corresponding gains or losses recognized within “electricity revenues” in the consolidated statements of operations and comprehensive income (loss). The Company recognized a net loss from these transactions of $5.0 million in the year ended December 31, 2013, compared to net gain of $2.3 million in the year ended December 31, 2012.

There were no transfers of assets or liabilities between Level 1 and Level 2 during the year ended December 31, 2013.

The fair value of the Company’s long-term debt is as follows:

	Fair Value		Carrying Amount	
	December 31,		December 31,	
	2013	2012	2013	2012
	(Dollars in millions)		(Dollars in millions)	
Olkaria III Loan - DEG	$40.3	$48.8	$39.5	$47.4
Olkaria III Loan - OPIC	279.6	220.0	299.9	220.0
Amatitlan Loan	34.8	38.9	31.5	34.3
Senior Secured Notes:				
Ormat Funding LLC ("OFC")	83.5	105.0	90.8	114.1
OrCal Geothermal LLC ("OrCal")	65.8	77.3	66.2	76.5
OFC 2 LLC ("OFC 2")	119.0	131.2	144.4	150.5
Senior Unsecured Bonds	270.6	273.2	250.6	250.9
Loan from institutional investors	20.1	27.7	19.5	27.0

The fair value of OFC Senior Secured Notes is determined using observable market prices as these securities are traded. The fair value of the other long-term debt is determined by a valuation model, which is based on a conventional discounted cash flow methodology and utilizes assumptions of current borrowing rates.The fair value of revolving lines of credit is determined using a comparison of market-based price sources that are reflective of similar credit ratings to those of the Company.

The carrying value of other financial instruments, such as revolving lines of credit, deposits, and other long-term debt approximates fair value.

ORMAT TECHNOLOGIES, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The following table presents the fair value of financial instruments as of December 31, 2013:

	Level 1	Level 2	Level 3	Total
	(Dollars in millions)			
Olkaria III - DEG	$—	$—	$40.3	$40.3
Olkaria III - OPIC	—	—	279.6	279.6
Amatitlan loan	—	—	34.8	34.8
Senior Secured Notes:				
OFC	—	83.5	—	83.5
OrCal	—	—	65.8	65.8
OFC 2	—	—	119.0	119.0
Senior unsecured bonds	—	—	270.6	270.6
Loan from institutional investors	—	—	20.1	20.1
Other long-term debt	—	23.3	—	23.3
Revolving credit lines with banks	—	112.0	—	112.0
Deposits	21.3	—	—	21.3

The following table presents the fair value of financial instruments as of December 31, 2012:

	Level 1	Level 2	Level 3	Total
	(Dollars in millions)			
Olkaria III Loan - DEG	$—	$—	$48.8	$48.8
Olkaria III Loan - OPIC	—	—	220.0	220.0
Amatitlan Loan	—	—	38.9	38.9
Senior Secured Notes:				
OFC	—	105.0	—	105.0
OrCal	—	—	77.3	77.3
OFC 2	—	—	131.2	131.2
Senior unsecured bonds	—	—	273.2	273.2
Loan from institutional investors	—	—	27.7	27.7
Other long-term debt	—	36.7	—	36.7
Revolving lines of credit	—	73.6	—	73.6
Deposits	21.7	—	—	21.7

Assets and Liabilities Measured at Fair Value on a Non-Recurring Basis

The North Brawley geothermal power plant was tested for impairment as of December 31, 2012 due to the low output and higher than expected operating costs. The plant was placed in service under its PPA with Southern California Edison in 2010. However, management found that the North Brawley geothermal field was significantly more difficult to operate than other fields of the Company and the power plant was unable to reach its design capacity of 50 MW and instead, operated at capacities between 20 MW and 33 MW. This generation level was achieved only after significant additional capital expenditures and higher than anticipated operating costs.

In order to improve the economics of the plant, the Company approached Southern California Edison to discuss various contractual alternatives to the PPA and, in early 2012 it reached a written understanding to engage in discussions with third parties about purchasing the power at better rates. However, in a letter dated January 14, 2013, Southern California Edison informed the Company that it is no longer interested in pursuing alternatives to the current PPA, thus retracting its permission to the Company to explore a replacement PPA with higher electricity prices.

As a result of Southern California Edison’s notification and the rates under the existing PPA, coupled with a further understanding of the cost and probability of success of additional well field work which has been accumulated in recent months, the Company has concluded that it will not be economical to continue to invest the substantial capital required to increase the generating capacity of the power plant. Accordingly, the Company decided to operate the plant at the current capacity level of approximately 27 MW and refrain from additional capital investment to expand the capacity.

ORMAT TECHNOLOGIES, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Based on these indicators, the power plant was tested for recoverability by estimating its future cash flows taking into consideration rates to be received under the PPA with Southern California Edison through the end of its term and expected market rates thereafter, possible penalties for underperformance during periods when the plant is expected to operate below the stated capacity in the PPA, projected capital expenditures and projected operating expenses over the life of the plant.

As a result, the North Brawley power plant was written down to its fair value of $32.0 million. The impairment loss of $229.1 million is presented in the consolidated statement of operations and comprehensive income (loss) under “Impairment Charges”.

In estimating the fair value for the power plant, the Company primarily relied on the “Income Approach”, using assumptions that the Company believes market participants would utilize in making such valuation. The “Income Approach” is based on the principle that the value of an asset is equal to the present value of the cash flows that the asset is expected to generate. To estimate the fair value of the power plant, a discounted cash flow (“DCF”) analysis was utilized whereby the cash flows expected to be generated by the power plant were discounted to their present value equivalent using the rate of return that reflects the relative risk of each asset, as well as the time value of money. This return, known as the weighted average cost of capital (“WACC”), an overall rate based upon the individual rates of return for invested capital (equity and interest-bearing debt), was calculated by weighting the acquired return on interest-bearing debt and common equity capital in proportion to their estimated percentage in the expected capital structure. The estimate for the WACC of 8% developed in the valuation is for independent power producers and geothermal power producers.

In addition to the WACC rate of 8%, other significant inputs of the future net cash flow estimates included in the valuation are generation output, average realized price, and operating costs. These future net cash flow estimates are classified as Level 3 within the fair value hierarchy. Below are the significant unobservable inputs for each year included in the valuation as of the year ended December 31, 2012.

(Dollars in thousands, except realized price)

	Valuation Technique	Amount or Range	Weighted Average

Generation output (MWh)	DCF	224,836			224,836
Average realized price ($/MWh)	DCF	$84.50	—	$111.25	$92.31
Operating costs	DCF	$12,687	—	$20,430	$16,163

OREG 4, a recovered energy generation power plant, was also tested for impairment in the third quarter of 2012 due to continued low run time of the compressor station that serves as it heat source, which resulted in low power generation and revenues. Based on these indicators, the power plant was tested for recoverability by estimating its future cash flows over the life of the plant.

As a result, the OREG 4 power plant was written down to its fair value of $3.6 million. The impairment loss of $7.3 million is presented in the consolidated statement of operations and comprehensive income (loss) under “Impairment Charges”.

In estimating the fair value for the power plant, the Company primarily relied on the “Income Approach”, using assumptions that the Company believes market participants would utilize in making such valuation. The “Income Approach” is based on the principle that the value of an asset is equal to the present value of the cash flows that the asset is expected to generate. To estimate the fair value of the power plant, a DCF analysis was utilized and the estimate for the WACC of 8% developed in the valuation is for independent power producers and geothermal power producers.

In addition to the WACC rate of 8%, other significant inputs of the future net cash flow estimates included in the valuation are generation output, average realized price, and operating costs. These future net cash flow estimates are classified as Level 3 within the fair value hierarchy. Below are the significant unobservable inputs for each year included in the valuation as of the quarter ended September 30, 2012.

ORMAT TECHNOLOGIES, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(Dollars in thousands, except realized price)

	Valuation Technique	Amount or Range	Weighted Average
Generation output (MWh)	DCF	11,916 — 15,456	15,097
Average realized price ($/MWh)	DCF	$49.00 — $71.50	$60.36
Operating costs	DCF	$86 — $595	$400

NOTE 7 — PROPERTY, PLANT AND EQUIPMENT AND CONSTRUCTION-IN-PROCESS

Property, plant and equipment

Property, plant and equipment, net, consist of the following:

	December 31, 2013	December 31, 2012 As Revised
	(Dollars in thousands)	
Land owned by the Company where the geothermal resource is located	$30,336	$32,396
Leasehold improvements	3,386	1,339
Machinery and equipment	101,104	100,499
Office equipment	17,492	15,218
Automobiles	5,745	5,816
Geothermal and recovered energy generation power plants, including geothermal wells and exploration and resource development costs:		
United States of America, net of cash grants and impairment charges	1,439,374	1,322,649
Foreign countries	448,161	312,412
Asset retirement cost	7,803	7,214

	2,053,401	1,797,543
Less accumulated depreciation	(601,065)	(544,670)
Property, plant and equipment, net	$1,452,336	$1,252,873

Depreciation expense for the years ended December 31, 2013, 2012, and 2011 amounted to $91,791,000, $89,876,000, and $89,600,000, respectively. Depreciation expense for the years ended December 31, 2013 and 2012 is net of the impact of the cash grant in the amount of $4,330,000 and $5,553,000, respectively. As of December 31, 2013 accumulated depreciation balance does not include MPC balance of $35,396,000.

U.S. Operations

The net book value of the property, plant and equipment, including construction-in-process, located in the United States was approximately $1,316,597,000 and $1,287,635,000 as of December 31, 2013 and 2012, respectively. These amounts as of December 31, 2013 and 2012 are net of cash grants in the amount of $127,675,000 and $117,320,000, respectively.

Impairment tests of the North Brawley and OREG 4 plants performed during the year ended December 31, 2012 resulted in impairment charges (see Note 6).

Foreign Operations

The net book value of property, plant and equipment, including construction-in-process, located outside of the United States was approximately $424,567,000 and $361,379,000 as of December 31, 2013 and 2012, respectively.

ORMAT TECHNOLOGIES, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The Company, through its wholly owned subsidiary, OrPower 4, Inc. ("OrPower 4") owns and operates geothermal power plants in Kenya. The net book value of assets associated with the power plants was $338,517,000 and $272,050,000 as of December 31, 2013 and 2012, respectively. The Company sells the electricity produced by the power plants to Kenya Power and Lighting Co. Ltd. ("KPLC") under a 20-year PPA. The Company has incurred costs of approximately $98,065,000 and $167,344,000 (included in construction-in-process) at December 31, 2013 and 2012, respectively, in connection with the construction of Plant 3, and the Phase III of the Plant 2 complex.

In May 2013 the Company sold the Momotombo Power Company, which operates the Momotombo power plant located in Nicaragua (see Note 16).

The Company, through its wholly owned subsidiary, Orzunil I de Electricidad, Limitada ("Orzunil"), owns a power plant in Guatemala. The geothermal resources used by the power plant are owned by Instituto Nacional de Elecrification ("INDE"), a Guatemalan power utility, who granted the use of these resources to Orzunil for the period of the PPA. The net book value of the assets related to the power plant was $18,846,000 and $21,628,000 at December 31, 2013 and 2012, respectively.

The Company, through its wholly owned subsidiary, Ortitlan, Limitada ("Ortitlan"), owns a power plant in Guatemala. The net book value of the assets related to the power plant was $52,272,000 and $43,360,000 at December 31, 2013 and 2012, respectively.

On December 2, 2013 the Company's wholly-owned subsidiary, Ormat International obtained control over the assets of Honduran GeoPlanares, including a PPA with ENEE, and a 30-year concession to use the geothermal resources in exchange for annual royalty payments of 12% of revenue if the project is successful, and return of the project to the seller after a 15 year operating period. The development of the project depends on the appraisal stage. Ormat has an option to abandon the project if the geothermal resource does not meet certain criteria specified in the agreement. The net book value of assets was immaterial at December 31, 2013.

Construction-in-process

Construction-in-process consists of the following:

	December 31, 2013	2012
	(Dollars in thousands)	
Projects under exploration and development:		
Up-front bonus lease costs	$30,141	$33,985
Exploration and development costs	38,220	32,302
Interest capitalized	1,278	1,278
	69,639	67,565
Projects under construction:		
Up-front bonus lease costs	27,473	29,160
Drilling and construction costs	184,767	283,873
Interest capitalized	6,948	15,543
	219,188	328,576
Total	$288,827	$396,141

ORMAT TECHNOLOGIES, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

	Projects under Exploration and Development			
	Up-front Bonus Lease Costs	Exploration and Development Costs	Capitalized Interest	Total
	(Dollars in thousands)			
Balance at December 31, 2010	$33,600	$ 20,997	$ 100	$54,697
Cost incurred during the year	3,232	19,226	1,498	23,956
Balance at December 31, 2011	36,832	40,223	1,598	78,653
Cost incurred during the year	—	3,782	420	4,202
Write off of unsuccessful exploration costs	(1,160)	(1,479)	—	(2,639)
Reclassification of exploration and development projects to drilling and construction	(1,687)	(10,224)	(740)	(12,651)
Balance at December 31, 2012	33,985	32,302	1,278	67,565
Cost incurred during the year	—	6,168	—	6,168
Write off of unsuccessful exploration costs	(3,844)	(250)	—	(4,094)
Reclassification of exploration and development				
Balance at December 31, 2013	$30,141	$ 38,220	$ 1,278	$69,639

	Projects under Construction			
	Up-front Bonus Lease Costs	Drilling and Construction Costs	Capitalized Interest	Total
	(Dollars in thousands)			
Balance at December 31, 2010	$31,179	$ 176,968	$ 7,790	$215,937
Cost incurred during the year	-	242,066	10,207	252,273
Reclassification of exploration and development				
Reclassification of completed projects to property, plant and equipment	-	(172,156)	(4,156)	(176,312)
Balance at December 31, 2011	31,179	246,878	13,841	291,898
Cost incurred during the year	-	216,894	11,541	228,435
Reclassification of exploration and development projects to drilling and construction	1,687	10,224	740	12,651
Reclassification of completed projects to property, plant and equipment	(3,706)	(190,123)	(10,579)	(204,408)
Balance at December 31, 2012	29,160	283,873	15,543	328,576
Cost incurred during the year	-	203,859	7,609	211,468
Reclassification of exploration and development				

Reclassification of completed projects to property, plant and equipment	(1,687)	(302,966)	(16,204)	320,857
Balance at December 31, 2013	$27,473	$ 184,766	$ 6,948	$219,188

150

ORMAT TECHNOLOGIES, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 8 — INTANGIBLE ASSETS

Intangible assets consist mainly of the Company's PPAs acquired in business combinations and amounted to $31,933,000 and $35,492,000, net of accumulated amortization of $31,890,000 and $28,654,000, as of December 31, 2013 and 2012, respectively. Amortization expense for the years ended December 31, 2013, 2012, and 2011 amounted to $3,280,000, $3,289,000, and $3,279,000, respectively.

Estimated future amortization expense for the intangible assets as of December 31, 2013 is as follows:

	(Dollars in thousands)
Year ending December 31:	
2014	$ 3,280
2015	3,280
2016	3,280
2017	2,944
2018	2,814
Thereafter	16,335
Total	$ 31,933

NOTE 9 — ACCOUNTS PAYABLE AND ACCRUED EXPENSES

Accounts payable and accrued expenses consist of the following:

	December 31,	
	2013	**2012**
	(Dollars in thousands)	

Trade payables	$49,619	$51,303
Salaries and other payroll costs	11,711	10,423
Customer advances	6,410	9,592
Accrued interest	9,277	9,110
Income tax payable	224	1,467
Property tax payable	4,671	4,399
Scheduling and transmission	1,300	594
Royalty accrual	1,531	1,646
Deferred revenues	5,750	-
Other	7,554	9,467
Total	$98,047	$98,001

151

ORMAT TECHNOLOGIES, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 10 — LONG-TERM DEBT AND CREDIT AGREEMENTS

Long-term debt consists of notes payable under the following agreements:

	December 31, 2013	2012
	(Dollars in thousands)	
Limited and non-recourse agreements:		
Loans:		
Non-recourse:		
Loan agreement with TCW (the Amatitlan power plant)	$31,509	$34,268
Limited recourse:		
Loan agreement with OPIC (the Olkaria III power plant)	299,946	220,000
Senior Secured Notes:		
Non-recourse:		
Ormat Funding LLC ("OFC")	90,840	114,136
OrCal Geothermal LLC ("OrCal")	66,156	76,548
Limited recourse:		
OFC 2 LLC ("OFC 2")	144,450	150,473
	632,902	595,425
Less current portion	(51,514)	(39,684)
Non-current portion	$581,387	$555,741
Full recourse agreements:		
Senior unsecured bonds	$250,596	$250,904
Loans from institutional investors	32,868	43,624
Loan agreement with DEG (the Olkaria III power plant)	39,474	47,369
Loan from a commercial bank	10,000	20,000
Revolving credit lines with banks	112,017	73,606
	444,955	435,503
Less current portion	(28,875)	(28,649)
Non-current portion	$416,080	$406,854

Loan Agreement with TCW (the Amatitlan Power Plant)

In May 2009, the Company's wholly owned subsidiary, Ortitlan, entered into a note purchase agreement, in an aggregate principal amount of $42.0 million which refinanced its investment in the 20 MW Amatitlan geothermal power plant located in Amatitlan, Guatemala (the "Amatitlan Loan"). The Amatitlan Loan was provided by TCW Global Project Fund II, Ltd. ("TCW"). The Amatitlan Loan will mature on June 15, 2016, and is payable in 28 quarterly installments. The Amatitlan Loan bears interest at a rate of 9.83%.

There are various restrictive covenants under the Amatitlan Loan, which include: (i) a projected 12-month debt service coverage ratio ("DSCR") of not less than 1.2; and (ii) a long-term debt to equity ratio not to exceed 4 (both of which are measured quarterly). If Ortitlan fails to comply with these financial ratios it will be prohibited from making distributions to its shareholders. In addition, subject to certain cure rights, such failure will constitute an event of default by Ortitlan. As of December 31, 2013, the projected 12-month DSCR was 1.61, and the debt to equity ratio was 2.21.

Debt service reserve

As required under the terms of the Amatitlan Loan, Ortitlan maintains an account which may be funded by cash or backed by letters of credit in an amount sufficient to pay scheduled debt service amounts, including principal and interest, due under the terms of the Amatitlan Loan in the following three months, and a well field reserve account. This restricted cash account is classified as current in the consolidated balance sheets. As of December 31, 2013 and 2012, the balance of such account was $1.0 million and $3.8 million, respectively**.** In addition, as of December 31, 2013 and 2012, part of the required debt service reserve was backed by a letter of credit in the amount of $3.1 million for both years (see Note 22).

ORMAT TECHNOLOGIES, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Finance Agreement with OPIC (the Olkaria III Complex)

On August 23, 2012, the Company's wholly owned subsidiary, OrPower 4 entered into a Finance Agreement with Overseas Private Investment Corporation ("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 the Olkaria III geothermal power complex in Kenya. The Finance Agreement was amended on November 9, 2012.

The OPIC Loan is comprised of up to 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. 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 the expansion of the Olkaria III geothermal power complex ("Plant 2"). 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 Olkaria III complex. In November 2013, an amount of $45.0 million was disbursed under this Tranche.

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 into a fixed interest rate. The average fixed interest rate for Tranche I, which has an outstanding balance of $81.4 million and matures on December 15, 2030 and Tranche II, which has an outstanding balance of $177.4 million and matures on June 15, 2030, is 6.31%. In November 2013, we fixed the interest rate for the Tranche III. The fixed interest rate for Tranche III which has an outstanding balance of $45.0 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 2.0% 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.

ORMAT TECHNOLOGIES, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The repayment of the remaining outstanding DEG Loan (see “Full-Recourse Third-Party Debt” below) in the amount of approximately $39.5 million as of December 31, 2013, 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 will become effective on December 15, 2014.

As of December 31, 2013, $299.9 million of the OPIC Loan was outstanding.

Debt service reserve

As required under the terms of the OPIC Loan, OrPower 4 maintains an account which may be funded by cash or backed by letters of credit in an amount sufficient to pay scheduled debt service amounts, including principal and interest, due under the terms of the OPIC Loan in the following six months. This restricted cash account is classified as current in the consolidated balance sheets. As of December 31, 2013 and 2012, the balance of the account was $10.1 million and $18.9 million, respectively. In addition, as of December 31, 2013, part of the required debt service reserve was backed by a letter of credit in the amount of $15.7 million (see Note 22).

Well drilling reserve

As required under the terms of the OPIC Loan, OrPower 4 may be required to maintain an account which may be funded by cash or backed by letters of credit to reserve funds for future well drilling, based on determination upon the completion of the expansion work.

OFC Senior Secured Notes

In February 2004, OFC, a wholly owned subsidiary, issued $190.0 million, 8.25% Senior Secured Notes ("OFC Senior Secured Notes") and received net cash proceeds of approximately $179.7 million, after deduction of issuance costs of approximately $10.3 million, which have been included in deferred financing costs in the consolidated balance sheet. The OFC Senior Secured Notes have a final maturity 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 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. The Company believes that the transition to variable energy prices under the Ormesa and Mammoth PPAs and the impact of the currently low natural gas prices on the revenues under these PPAs may cause OFC to not meet the DSCR ratio requirements for making distributions, but it does not believe that there will be an event of default by OFC. As of December 31, 2013 (the last measurement date of the covenants), the actual historical 12-month DSCR was 1.29.

In February 2013, the Company acquired from OFC noteholders OFC Senior Secured Notes with an outstanding aggregate principal amount of $12.8 million and recognized a gain of approximately $0.8 million in the first quarter of 2013.

In January 2014, the Company acquired from OFC noteholders OFC Senior Secured Notes with an outstanding aggregate principal amount of $13.2 million and will recognize a gain of approximately $0.3 million in the first quarter of 2014.

ORMAT TECHNOLOGIES, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

OFC may redeem the OFC Senior Secured Notes, in whole or in part, at any time, at redemption price equal to the principal amount of the OFC Senior Secured Notes to be redeemed plus accrued interest, premium and liquidated damages, if any, plus a “make-whole” premium. Upon certain events, as defined in the indenture governing the OFC Senior Secured Notes, OFC may be required to redeem a portion of the OFC Senior Secured Notes at a redemption price ranging from 100% to 101% of the principal amount of the OFC Senior Secured Notes being redeemed plus accrued interest, premium and liquidated damages, if any.

Debt service reserve

As required under the terms of the OFC Senior Secured Notes, OFC maintains an account which may be funded by cash or backed by letters of credit (see below) in an amount sufficient to pay scheduled debt service amounts, including principal and interest, due under the terms of the OFC Senior Secured Notes in the following six months. This restricted cash account is classified as current in the consolidated balance sheets. As of each of December 31, 2013 and 2012, the balance of such account was $2.9 million. In addition, as of each of December 31, 2013 and 2012, part of the required debt service reserve was backed by a letter of credit in the amount of $10.6 million (see Note 22).

OrCal Senior Secured Notes

In December 2005, OrCal, a wholly owned subsidiary, issued $165.0 million, 6.21% Senior Secured Notes (“OrCal Senior Secured Notes”) and received net cash proceeds of approximately $161.1 million, after deduction of issuance costs of approximately $3.9 million, which have been included in deferred financing costs in the consolidated balance sheet. The OrCal Senior Secured Notes have been rated BBB- by Fitch Ratings. The OrCal Senior Secured Notes have a final maturity 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 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, 2013 (the last measurement date of the covenants), the actual historical 12-month DSCR was 1.30.

OrCal may redeem the OrCal Senior Secured Notes, in whole or in part, at any time at a redemption price equal to the principal amount of the OrCal Senior Secured Notes to be redeemed plus accrued interest, and a “make-whole” premium. Upon certain events, as defined in the indenture governing the OrCal Senior Secured Notes, OrCal may be required to redeem a portion of the OrCal Senior Secured Notes at a redemption price of 100% of the principal amount of the OrCal Senior Secured Notes being redeemed plus accrued interest.

Debt service reserve

As required under the terms of the OrCal Senior Secured Notes, OrCal maintains an account which may be funded by cash or backed by letters of credit (see below) in an amount sufficient to pay scheduled debt service amounts, including principal and interest, due under the terms of the OrCal Senior Secured Notes in the following six months. This restricted cash account is classified as current in the consolidated balance sheets. As of December 31, 2013 and 2012, the balance of such account was $3.0 million and $2.6 million, respectively. In addition, as of December 31, 2013 and 2012, part of the required debt service reserve was backed by a letter of credit in the amount of $10.2 million and $4.9 million, respectively (see Note 22).

ORMAT TECHNOLOGIES, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

OFC 2 Senior Secured Notes

In September 2011, the Company's subsidiary OFC 2 and its wholly owned project subsidiaries (collectively, the "OFC 2 Issuers") entered into a note purchase agreement (the "Note Purchase Agreement") with OFC 2 Noteholder Trust, as purchaser, John Hancock Life Insurance Company (U.S.A.), 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's Senior Secured Notes ("OFC 2 Senior Secured Notes") due December 31, 2034.

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 will guarantee 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.

On October 31, 2011, the 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.

Issuance of the Series B Notes is dependent on the Jersey Valley power plant reaching certain operational targets in addition to the other conditions precedent noted above. If issued, the aggregate principal of the Series B Notes will not exceed $28.0 million, and such proceeds would be used to finance a portion of the construction costs of Phase I of the Jersey Valley power plant.

The OFC 2 Issuers have sole discretion regarding whether to commence construction of Phase II of any of the Jersey Valley, McGinness Hills and Tuscarora power plants. If a facility Phase II is undertaken for any of the power plants, the OFC 2 Issuers may issue Phase II tranches of Notes, comprised of one or more of Series C Notes, Series D Notes, Series E Notes and Series F Notes, to finance a portion of the construction costs of such Phase II of any facility. The aggregate principal amount of all Phase II Notes may not exceed $170.0 million. The aggregate principal amount of each series of Notes comprising a Phase II tranche will be determined by the OFC 2 Issuers in their sole discretion provided that certain financial ratios are satisfied pursuant to the terms of the Note Purchase Agreement and subject to the aggregate limit noted above.

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 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). As of December 31, 2013 (the last measurement date of the covenants), the actual DSCR for the fourth quarter of 2013 was 1.79 and the pro-forma 12-month DSCR was 2.25.

ORMAT TECHNOLOGIES, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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

Debt service reserve; other restricted funds

Under the terms of the OFC 2 Senior Secured Notes, OFC 2 is required to maintain a debt service reserve and certain other reserves, as follows:

(i) A debt service reserve account which may be funded by cash or backed by letters of credit (see below) in an amount sufficient to pay scheduled debt service amounts, including principal and interest, due under the terms of the OFC 2 Senior Secured Notes in the following six months. This restricted cash account is classified as current in the consolidated balance sheet. As of December 31, 2013, part of the required debt service reserve was backed by a letter of credit in the amount of $10.4 million (see Note 22).

(ii) A performance level reserve account, intended to provide additional security for the OFC 2 Senior Secured Notes, which may be funded by cash or backed by letters of credit. This reserve builds up over time and reduces gradually each time the project achieves certain milestones. Upon issuance of the Series A Notes, this reserve was funded in the amount of $28.0 million. As of December 31, 2013, the balance of such account was $45.7 million, and in addition OFC 2 funded $10.0 million in a letter of credit issued, that is required to be maintained at all times until this reserve reduces to zero.

(iii)

Under the terms of the OFC 2 Senior Secured Notes, OFC 2 is also required to maintain a well field drilling and maintenance reserve that builds up over time and is dedicated to costs and expenses associated with drilling and maintenance of the project's well field, which may be funded by cash or backed by letters of credit. Certain other reserves are required in the event OFC 2 elects to commence construction of Phase II of any facility and fund such construction with any Series of Notes (other than Series A and Series B Notes).

Senior Unsecured Bonds

In August 2010, the Company entered into a trust instrument governing the issuance of, and accepted subscriptions for, an aggregate principal amount of approximately $142.0 million of senior unsecured bonds (the “Bonds”). 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%, payable semi-annually. In February 2011, the Company accepted subscription for an aggregate principal amount of approximately $108.0 million of additional senior unsecured bonds (the “Additional Bonds”) under two addendums to the trust instrument. The terms and conditions of the Additional Bonds are identical to the original Bonds. The Additional Bonds were issued at a premium which reflects an effective fixed interest of 6.75%.

Loans from institutional investors

In July 2009, the Company entered into a 6-year loan agreement of $20.0 million with a group of institutional investors (the “First Loan”). The First Loan matures on July 16, 2015, is payable in 12 semi-annual installments, which commenced on January 16, 2010, and bears interest of 6.5%.

ORMAT TECHNOLOGIES, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

In July 2009, the Company entered into an 8-year loan agreement of $20.0 million with another group of institutional investors (the “Second Loan”). The Second Loan matures on August 1, 2017, is payable in 12 semi-annual installments, which commenced on February 1, 2012, and bears interest at 6-month LIBOR plus 5.0%.

In November 2010, the Company entered into a 6-year loan agreement of $20.0 million with a group of institutional investors (the “Third Loan”). The Third Loan matures on November 16, 2016, is payable in ten semi-annual installments, which commenced on May 16, 2012, and bears interest of 5.75%.

Loan Agreement with DEG (the Olkaria III Complex)

In March 2009, the Company’s wholly owned subsidiary, OrPower 4, entered into a project financing loan of $105.0 million to refinance its investment in Phase I of the Olkaria III complex located in Kenya (the “DEG Loan”). The DEG Loan was provided by a group of European Development Finance Institutions (“DFIs”) arranged by DEG — Deutsche Investitions — und Entwicklungsgesellschaft mbH (“DEG”). The first disbursement of $90.0 million occurred on March 23, 2009 and the second disbursement of $15.0 million occurred on July 10, 2009. The DEG Loan will mature on December 15, 2018, and is payable in 19 equal semi-annual installments, commencing December 15, 2009. Interest on the DEG Loan is variable based on 6-month LIBOR plus 4.0% and OrPower 4 had the option to fix the interest rate upon each disbursement. Upon the first disbursement, the Company fixed the interest rate on $77.0 million of the DEG Loan at 6.90%.

In October 2012, OrPower 4, DEG and the parties thereto amended and restated the DEG Loan agreement (the “DEG Amendment”). The DEG Amendment became effective on November 9, 2012 upon the execution by OrPower 4 of the Tranche I and Tranche II Notes and the related disbursements of the proceeds thereof under the OPIC Finance Agreement (as described above). The amended and restated DEG Loan Agreement provides for: (i) the prepayment in full of two loans thereunder in the total principal amount of approximately $20.5 million; (ii) 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; and (iii) the establishment of a LIBOR floor of 1.25% in respect of one of the loans under the DEG Loan agreement, and (iv) the elimination of most of the affirmative and negative covenants under the DEG Loan agreement and certain other conforming provisions to take into account OrPower 4’s execution of the OPIC Finance Agreement and its obligations thereunder.

Loan from a commercial bank

In November 2009, the Company entered into a 5-year loan agreement of $50.0 million with a commercial bank. The bank loan matures on November 10, 2014 and is payable in 10 semi-annual installments, which commenced on May 10, 2010, and bears interest at 6-month LIBOR plus 3.25%.

Revolving credit lines with commercial banks

As of December 31, 2013, the Company has credit agreements with eight commercial banks for an aggregate amount of $485.1 million (including $50.0 million from Union Bank, N.A. ("Union Bank") and $25.0 million from HSBC), see below. Under the terms of these credit agreements, the Company, or its 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 $283.0 million; and (ii) the issuance of one or more letters of credit in the amount of up to $202.1 million. The credit agreements mature between end of March 2014 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, 2013, loans in the total amount of $112.0 million were outstanding, and letters of credit with an aggregate stated amount of $210.9 million were issued and outstanding under such credit agreements. The $112.0 million in loans are for terms of three months or less and bear interest at an annual weighted average rate of 2.56%.

ORMAT TECHNOLOGIES, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Restrictive covenants

The Company's obligations under the credit agreements, the loan agreements, and the trust instrument governing the bonds, described above, are unsecured, but 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, as well as the trust instrument contain cross-default provisions with respect to other material indebtedness owed by us to any third party. In some cases, the Company has agreed to maintain certain financial ratios, which are measured quarterly, such as: (i) equity of at least $600.0 million and in no event less than 30% of total assets; (ii) 12-month debt, net of cash, cash equivalents marketable securities and short-term bank deposits to Adjusted EBITDA ratio not to exceed 7; and (iii) dividend distribution not to exceed 35% of net income for that year. As of December 31, 2013: (i) total equity was $745.1 million and the actual equity to total assets ratio was 34.5%, and (ii) the 12-month debt, net of cash, cash equivalents marketable securities and short-term bank deposits to Adjusted EBITDA ratio was 4.50. During the year ended December 31, 2013, the Company distributed interim dividends in an aggregate amount of $3.6 million. Although the Company reported a net loss for the year ended December 31, 2012, under the credit agreements, the loan agreements, and the trust instrument governing the bonds the Company can distribute interim dividends on the basis of its estimate of its net income for the year. Since the Company incurred a loss for the year ended December 31, 2012, an adjustment for the distributable dividend in the amount of $3.6 million was made in the year ended December 31, 2013. 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.

Credit agreement with Union Bank

In February 2012, the Company's wholly owned subsidiary, Ormat Nevada Inc. ("Ormat Nevada"), entered into an amended and restated credit agreement with Union Bank. Under the amended and restated agreement, the credit termination date was extended to February 7, 2014 (which was subsequently extended to March 31, 2014 pursuant to Amendment No. 1 to the agreement), and the aggregate amount available under the credit agreement was increased from $39.0 million to $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, the Company entered into a guarantee in favor of the administrative agent for the benefit of the banks, pursuant to which the Company 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, which include 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 2.58; (ii) the 12-month DSCR was 2.47; and (iii) the distribution leverage ratio was 1.34. 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, 2013, letters of credit in the aggregate amount of $45.6 million remain issued and outstanding under this credit agreement with Union Bank.

ORMAT TECHNOLOGIES, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Credit agreement with HSBC

In May 2013, Ormat Nevada, a wholly owned subsidiary of the Company, entered into a credit agreement with HSBC Bank USA, N.A for one year with annual renewals. 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 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 2.58; (ii) the 12-month DSCR was 2.47; and (iii) the distribution leverage ratio was 1.34. 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, 2013, letters of credit in the aggregate amount of $20.8 million remain issued and outstanding under this credit agreement.

Future minimum payments

Future minimum payments under long-term obligations, excluding revolving credit lines with commercial banks, as of December 31, 2013 are as follows:

	(Dollars in thousands)
Year ending December 31:	
2014	$ 80,389
2015	74,386
2016	89,604
2017	311,890
2018	53,954

Thereafter	355,617
Total	$ 965,840

NOTE 11 — PUNA POWER PLANT LEASE TRANSACTIONS

In 2005, the Company’s wholly owned subsidiary in Hawaii, Puna Geothermal Ventures (“PGV”), entered into transactions involving the original geothermal power plant of the Puna complex located on the Big Island (the “Puna Power Plant”).

Pursuant to a 31-year head lease (the “Head Lease”), PGV leased Puna Power Plant to an unrelated company in return for prepaid lease payments in the total amount of $83.0 million (the “Deferred Lease Income”). The carrying value of the leased assets as of December 31, 2013 and 2012 amounted to $36.9 million and $39.6 million, net of accumulated depreciation of $25.5 million and $22.8 million, respectively. The unrelated company (the “Lessor”) simultaneously leased back the Puna Power Plant to PGV under a 23-year lease (the “Project Lease”). PGV’s rent obligations under the Project Lease will be paid solely from revenues generated by the Puna Power Plant under a PPA that PGV has with Hawaii Electric Light Company (“HELCO”). The Head Lease and the Project Lease are non-recourse lease obligations to the Company. PGV’s rights in the geothermal resource and the related PPA have not been leased to the Lessor as part of the Head Lease but are part of the Lessor’s security package.

The Head Lease and the Project Lease are being accounted for separately. Each was classified as an operating lease in accordance with the accounting standards for leases. The Deferred Lease Income is amortized into revenue, using the straight-line method, over the 31-year term of the Head Lease. Deferred transaction costs amounting to $4.2 million are being amortized, using the straight-line method, over the 23-year term of the Project Lease.

ORMAT TECHNOLOGIES, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Future minimum lease payments under the Project Lease, as of December 31, 2013, are as follows:

	(Dollars in thousands)
Year ending December 31:	
2014	$ 8,647
2015	8,222
2016	8,374
2017	8,747
2018	8,944
Thereafter	12,932
Total	$ 55,866

Depository accounts

As required under the terms of the lease agreements, there are certain reserve funds that need to be managed by the indenture trustee in accordance with certain balance requirements. Such reserve funds amounted to $4.3 million and $4.4 million as of December 31, 2013 and 2012, respectively, and were included in restricted cash accounts in the consolidated balance sheets and were classified as current as they were used for current payments.

Distribution account

PGV maintains an account to deposit its remaining cash, after making all of the necessary payments and transfers as provided for in the lease agreements, in order to make distributions to the Company’s wholly owned subsidiary, Ormat Nevada. The distributions are allowed only if PGV maintains various restrictive covenants under the lease agreements, which include limitations on additional indebtedness. As of December 31, 2013 and 2012, the balance of such account was $0.

NOTE 12 —TAX MONETIZATION TRANSACTIONS

OPC TRANSACTION

In June 2007, the Company's wholly owned subsidiary Ormat Nevada entered into agreements with affiliates of Morgan Stanley & Co. Incorporated and Lehman Brothers Inc. (Morgan Stanley Geothermal LLC and Lehman-OPC LLC), under which those investors purchased, for cash, interests in a newly formed subsidiary of Ormat Nevada, OPC LLC ("OPC"), entitling the investors to certain tax benefits (such as production tax credits ("PTCs") and accelerated depreciation) and distributable cash associated with four geothermal power plants.

The first closing under the agreements occurred in 2007 and covered the Company's 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 production tax credits and taxable income or loss (together, the "Economic Benefits"). Once Ormat Nevada recovered the capital that it has invested in the power plants, which occurred in the fourth quarter of 2010, the investors receive both the distributable cash flow and the Economic Benefits. The investors' return is limited by the term of the transaction. 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 buy out the investors' remaining interest in OPC at the then-current fair market value or, if greater, the investors' capital account balances in OPC. Should Ormat Nevada exercise this purchase option, it would thereupon revert to being sole owner of the power plants.

ORMAT TECHNOLOGIES, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The Class B membership units are provided with a 5% residual economic interest in OPC. The 5% residual interest commences on achievement by the investors of a contractually stipulated return that triggers the OPC Flip Date. The actual OPC Flip Date is not known with certainty and is determined by the operating results of OPC. This residual 5% interest represents a noncontrolling interest and is not subject to mandatory redemption or guaranteed payments. Cash is distributed each period in accordance with the cash allocation percentages stipulated in the agreements. Until the fourth quarter of 2010, Ormat Nevada was allocated the cash earnings in OPC and therefore, the amount allocated to the 5% residual interest represented the noncash loss of OPC which principally represented depreciation on the property, plant and equipment. As from the fourth quarter of 2010, the distributable cash is allocated to the Class B membership units. As a result of the acquisition by Ormat Nevada, on October 30, 2009, of all of the Class B membership units of OPC held by Lehman-OPC LLC (see below), the residual interest decreased to 3.5%. Such residual interest increased to 5% on February 3, 2011 when Ormat Nevada sold its Class B membership units to JPM Capital Corporation ("JPM") (see below).

The Company's voting rights in OPC are based on a capital structure that is comprised of Class A and Class B membership units. Through Ormat Nevada, the Company owns all of the Class A membership units, which represent 75% of the voting rights in OPC. The investors own all of the Class B membership units, which represent 25% of the voting rights in OPC. In the period from October 30, 2009 to February 3, 2011, the Company owned, through Ormat Nevada, all of the Class A membership units, which represented 75% of the voting rights in OPC, and 30% of the Class B membership units, which represented 7.5% of the voting rights of OPC. In total the Company had 82.5% of the voting rights in OPC as of December 31, 2010. In that period, the investors owned 70% of the Class B membership units, which represented 17.5% 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.

On October 30, 2009, Ormat Nevada acquired from Lehman-OPC LLC all of the Class B membership units of OPC held by Lehman-OPC pursuant to a right of first offer for a price of $18.5 million. A substantial portion of the initial sale of the Class B membership units by Ormat Nevada was accounted for as a financing transaction. As a result, the repurchase of these interests at a discount resulted in a pre-tax gain of $13.3 million in the year ended December 31, 2009. In addition, an amount of approximately $1.1 million has been reclassified from noncontrolling interest to additional paid-in capital representing the 1.5% residual interest of Lehman-OPC's Class B membership units.

On February 3, 2011, Ormat Nevada sold to JPM all of the Class B membership units of OPC that it had acquired on October 30, 2010 for a sale price of $24.9 million in cash. The Company did not record any gain from the sale of its Class B membership interests in OPC to JPM. A substantial portion of the Class B membership units are accounted for as a financing transaction. As a result, the majority of these proceeds were recorded as a liability. In addition, $2.3 million has been reclassified from additional paid-in capital to noncontrolling interest representing the 1.5% residual interest of JPM's Class B membership units.

ORTP TRANSACTION

In January 2013, Ormat Nevada entered into agreements with JP Morgan ("JPM") under which JPM purchased interests in a newly formed subsidiary of Ormat Nevada, ORTP, LLC ("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 up to maximum amount of $11.0 million.

ORMAT TECHNOLOGIES, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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% 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 buy out 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 5.0% (allocation of income and loss) and 2.5% (allocation of cash) residual economic interest in ORTP. The 5.0% and 2.5% residual 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.

The Company’s voting rights in ORTP are based on a capital structure that is comprised of Class A and Class B membership units. Through Ormat Nevada the Company owns all of the Class A membership units, which represent 75% of the voting rights in ORTP. JPM owns all of the Class B membership units, which represent 25% 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.

NOTE 13 — ASSET RETIREMENT OBLIGATION

The following table presents a reconciliation of the beginning and ending aggregate carrying amount of asset retirement obligation for the years presented below:

	Year Ended December 31,	
	2013	2012
	(Dollars in thousands)	
Balance at beginning of year	$19,289	$21,284
Revisions in estimated cash flows	(2,742)	(3,696)
Liabilities incurred	588	—
Accretion expense	1,544	1,701
Balance at end of year	$18,679	$19,289

During the year ended December 31, 2013, the Company decreased the aggregate carrying amount of its asset retirement obligation by $2,742,000 due to changes in price estimates and useful life.

During the year ended December 31, 2012, the Company decreased the aggregate carrying amount of its asset retirement obligation by $3,696,000 due to changes in useful life and price estimates.

ORMAT TECHNOLOGIES, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 14 — STOCK-BASED COMPENSATION

The Company makes an estimate of expected forfeitures and recognizes compensation costs only for those stock-based awards expected to vest. As of December 31, 2013, the total future compensation cost related to unvested stock-based awards that are expected to vest is $10,258,000, which amount will be recognized over a weighted average period of 1.4 years.

During the years ended December 31, 2013, 2012 and 2011, the Company recorded compensation related to stock-based awards as follows:

	Year Ended December 31,		
	2013	**2012**	**2011**
	(Dollars in thousands)		
Cost of revenues	$3,971	$4,225	$4,325
Selling and marketing expenses	494	542	600
General and administrative expenses	1,799	1,611	1,747
Total stock-based compensation expense	6,264	6,378	6,672
Tax effect on stock-based compensation expense	783	797	834
Net effect of stock-based compensation expense	$5,481	$5,581	$5,838

During the third and fourth quarters of 2013, the Company evaluated the trends in the stock-based award forfeiture rate and determined that the actual rates are 7.5% and 7.2%, respectively. This represents an increase of 1.1% and 0.8%, respectively from the estimate made in the third quarter of 2012. As a result of the increase in the estimated forfeiture rate, the stock based compensation expense decreased by an immaterial amount.