ORMAT TECHNOLOGIES, INC.
Form 10-K
February 29, 2012
Table of Contents

UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-K

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

For the fiscal year ended December 31, 2011

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)

Registrant s telephone number, including area code:

(775) 356-9029

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

Title of Each Class	Name of Each Exchange on Which Registered

Ormat Technologies, Inc. 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 þ

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 þ

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 þ 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 þ 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 þ	Non-accelerated filer ¨ (Do not check if a smaller reporting company)	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 þ

As of June 30, 2011, 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 $401,116,975 based on the closing price as reported on the New York Stock Exchange.

The number of outstanding shares of common stock of the registrant, as of February 24, 2012, was 45,430,886.

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, 2011.

Table of Contents

ORMAT TECHNOLOGIES, INC.

FORM 10-K FOR THE YEAR ENDED DECEMBER 31, 2011

TABLE OF CONTENTS

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
Amatitlan Loan	Initial $42,000,000 in 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)

Table of Contents

Term	**Definition**
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 Nicaraguense de Transmision
ENEL	Empresa Nicaraguense de Electricitdad
Enthalpy	The total energy control 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.
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
Flip Date	Date on which the holders of Class B membership units in OPC achieve a target after-tax yield on their investment in OPC.
FPA	U.S. Federal Power Act, as amended
GAAP	Generally accepted accounting principles
GDC	Geothermal Development Company
GDL	Geothermal Development Limited
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

Table of Contents

Term	Definition
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.)
KenGen	Kenya Electricity Generating Company Ltd.
Kenyan Energy Act	Kenyan Energy Act, 2006
KETRACO	Kenya Electricity Transmission Company Limited
KLP	Kapoho Land Partnership
kVa	Kilovolt-ampere
KPLC	Kenya Power and Lighting Co. Ltd.
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
MW	Megawatt One MW is equal to 1,000 kW or one million watts
MWh	Megawatt hour(s), a measure of power produced
NBPL	Northern Border Pipe Line Company
NIS	New Israeli Shekel
NGP	Nevada Geothermal Power Inc.
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	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	Senior Secured Notes Due 2034 issued by OFC 2
Olkaria Loan	Initial $105,000,000 in aggregate principal amount borrowed by OrPower 4 from a group of European DFIs
OMPC	Ormat Momotombo Power Company, a wholly owned subsidiary of the Company
OPIC	Overseas Private Investment Corporation

Table of Contents

Term	Definition
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.
OrCal	OrCal Geothermal Inc., a wholly owned subsidiary of the Company
OrCal Senior Secured Notes	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
Orzunil	Orzunil I de Electricidad, Limitada, a wholly owned subsidiary of the Company
Parent	Ormat Industries Ltd.
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.
PPA	Power purchase agreement
ppm	Part per million

Table of Contents

Term	**Definition**
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.
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
Senior Unsecured Bonds	7% Senior Unsecured Bonds Due 2017 issued by the Company
Securities Act	U.S. Securities Act of 1933, as amended
SOX Act	Sarbanes-Oxley Act of 2002
Solar PV	Solar photovoltaic
Southern California Edison	Southern California Edison Company
SPE(s)	Special purpose entity(ies)
SRAC	Short Run Avoided Costs
Sunday Energy	Sunday Energy Ltd.
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
W&M	Watts & More Ltd.
WHOH	Waste Heat Oil Heaters

Table of Contents

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 , predicts , projects , poter 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 report are primarily located in the material set forth under the headings Item 7 Management s Discussion and Analysis of Financial Condition and Results of Operations contained in Part II, Item 1A Risk Factors contained in Part I, and Notes to Financial Statements contained in Part II, 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. 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;
- operating risks, including equipment failures and the amounts and timing of revenues and expenses;
- geothermal resource risk (such as the heat content of the reservoir, useful life and geological formation);
- financial market conditions and the results of financing efforts;
- the impact of fluctuations in 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;

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 incentives for the production of renewable energy 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 similar geothermal energy projects, including any such new geothermal energy projects developed in the future, and from alternative electricity producing technologies;

the effect of and changes in economic conditions in the areas in which we operate;

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 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;

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;

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; and

development and construction of the Solar PV projects may not materialize as planned.

Table of Contents

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 Technologi 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 two business segments, which we refer to as our Electricity Segment and Product Segment. In our Electricity 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. In our Product 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 power plants and recovered energy plants, as well as the geothermal and recovered energy-based power plants and a Solar PV power plant that are under construction, and countries with projects under development and exploration.

Table of Contents

The charts below show the relative contributions of the Electricity Segment and the Product Segment to our consolidated revenues and the geographical breakdown of our segment revenues for our fiscal year ended December 31, 2011. Additional information concerning our segment operations, including year-to-year comparisons of revenues, the geographical breakdown of revenues, cost of revenues, results of operations, and trends and uncertainties is provided below in Item 7 Management s Discussion and Analysis of Financial Condition and Results of Operations and Item 8 Financial Statements and Supplementary Data .

The following chart sets forth a breakdown of revenues for the year ended December 31, 2011:

The following chart sets forth the geographical breakdown of the revenues attributable to our Electricity Segment for the year ended December 31, 2011:

11

All of our revenues attributable to our Product Segment for the year ended December 31, 2011 were from foreign operations.

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. Therefore, electricity produced from geothermal energy sources contributes significantly less to local and regional incidences of acid rain and global warming 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.

We have expanded our activity to the Solar PV industry. We are constructing a new utility-scale Solar PV project near our Heber complex in California and we are developing other Solar PV projects in Israel.

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.

Table of Contents

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 24, 2012. 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	Nevada	100%	25.0
Heber Complex	California	100%	92.0
Jersey Valley[(3)]	Nevada	100%	12.0
Mammoth Complex	California	100%	29.0
North Brawley[(4)]	California	100%	33.0
Ormesa Complex	California	100%	54.0
Puna Complex	Hawaii	100%	38.0
Steamboat Complex	Nevada	100%	86.0
Tuscarora[(5)]	Nevada	100%	18.0
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	Colorado	100%	3.5
Total for domestic power plants			**440.0**
Foreign			
Geothermal			
Amatitlan	Guatemala	100%	18.0
Momotombo	Nicaragua	100%	22.0
Olkaria III Complex	Kenya	100%	52.0
Zunil	Guatemala	100%	24.0
Total for foreign power plants			**116.0**
Total for all power plants			**556.0**

(1) We own and operate all of our power plants other than the Momotombo power plant in Nicaragua, which we do not own but which we control and operate through a concession arrangement with the Nicaraguan government. Two financial institutions hold equity interests in one of our consolidated subsidiaries (OPC) that 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. In the above table, we show these power plants as being 100% owned because all of the generating capacity is owned by OPC and we control the operation of the power plants. The nature of the equity interests held by the financial institution is described in Item 7 Management s Discussion and Analysis of Financial Condition and Results of Operations under the heading OPC 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

Table of Contents

the Zunil power plant, the energy output of the power plant was sold, until September 2011, under a take or pay arrangement, under which 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 the geothermal power plants in commercial operation in 2011, excluding the North Brawley power plant, which operates at partial load, was approximately 88%. The Capacity Factor of the REG power plants in 2011 was approximately 85%.

(3) The Jersey Valley power plant is not operating at full capacity. Detailed information on the Jersey Valley power plant is provided under Description of our Power Plants below.

(4) The North Brawley power plant is not operating at full capacity. Detailed information on the North Brawley power plant is provided under Description of our Power Plants below.

(5) The Tuscarora power plant commenced commercial operation on January 11, 2012.

Substantially all of the revenues that we currently derive from the sale of electricity are pursuant to long-term PPAs. Approximately 53.2% of our total revenues in the year ended December 31, 2011 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 development of new power plants, construction of new power plants and expansion of existing power plants. Our growth plan includes our share of approximately 175 MW in generating capacity from geothermal power plants in the United States and Kenya that are expected to come on-line in the next two years. In addition, we expect to add, in three phases, a total of approximately 42 MW, which is our share in the Sarulla project in Indonesia.

In addition, we are constructing a 10 MW Solar PV project in the U.S. and are developing approximately 18 ground-mounted and roof-top Solar PV projects in Israel. Our share of the expected generation capacity of these projects is 130 MW. However, due to the competition in the Solar PV market in Israel, combined with a relatively low cap on the feed-in-tariff, we expect that only a portion of the Solar PV projects in our Israeli development pipeline will be ultimately constructed.

We have a substantial land position that is expected to support future geothermal development on, which we have started or plan to start exploration activity. This land position is approximately 675,000 acres in 42 sites. This is comprised of various leases and concessions, exploration concessions for geothermal resources and an option to enter into geothermal leases. We have started or plan to start exploration activity at a number of these sites.

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.

Table of Contents

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 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 climate conditions, whether hot or cold. 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. The energy necessary to operate a geothermal power plant is typically obtained from several such wells which are drilled using established technology that is in some respects similar to that employed in the oil and gas industry. Geothermal production wells are normally located within approximately one to two miles of the power plant as geothermal fluids cannot be transported economically 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 24hr/day weather independent power, the variable operating costs are lower.

EGS An EGS has been broadly defined as a subsurface system that may be artificially created to extract heat from hot rock where the characteristics required for a hydrothermal system, i.e., permeability and aquifers,

Table of Contents

are 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. This application is referred to as Co-produced Fluids . 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 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 heat exchanger, which heats a secondary working fluid which has a low boiling point. This is typically an organic fluid, such as isopentane or isobutene, which is vaporized and is used to drive the turbine. The organic fluid is then condensed in a condenser which may be cooled by air or by water from a cooling tower. The condensed fluid is then recycled back to the heat exchanger, closing the cycle within the sealed system. The cooled geothermal fluid is then reinjected back into the reservoir. The binary technology is depicted in the graphic 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 in the plant, where any

16

Table of Contents

remaining water droplets are removed. This produces a stream of dry saturated steam, which drives a 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 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 graphic below.

In some instances, the wells directly produce dry steam (the flashing occurring underground). In such cases, the steam is fed directly to the steam turbine and the rest of the system is similar to the flash power plant described above.

Ormat s Proprietary Technology

Our proprietary technology may be used in power plants operating according to the Organic Rankine Cycle, only or in combination with, various other commonly used thermodynamic technologies that convert heat to mechanical power. 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 our motive fluids 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. In particular, we are 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 recovered energy systems and new motive fluids.

Table of Contents

We also construct 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. Our combined cycle technology is depicted in the graphic 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 tower 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, low RPM, temperature and pressure in the OEC, a high efficiency turbine, and the fact that there is no contact between the turbine itself and often corrosive geothermal fluids.

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 industry. 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. The same advantages of using the Organic Rankine Cycle apply here as well. In addition, our technology allows for better load following than conventional steam turbines exhibit, requires no water treatment as it is air cooled, and does not require the continuous presence of a steam licensed operator on site.

Table of Contents

Our REG technology is depicted in the graphic below.

Patents

We have been granted 82 U.S. patents (and about 20 pending patents) that 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 system-related patents cover not only a particular component but also the overall effectiveness of the plant s systems from the fuel (e.g., geothermal fluid, waste heat, biomass or solar) to generated electricity. The duration of such patents ranges from one year to seventeen years. No single patent on its own is material to our business.

The products-related patents cover components which include turbines, heat exchangers, seals and controls. The system 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 use of two-phase fluids as well as processes related to EGS. A number of patents cover the 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.

Research and Development

We are conducting research and development of new EGS technologies and their application to enhance our power plants without using any additional fluid supply. We are undertaking this development effort at our Desert Peak 2 and Brady power plants in Nevada in cooperation with GeothermEx Inc., and a number of universities and national laboratories, with funding support from the DOE.

We are also continuing with our 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 evaporative cooling system, condensing equipment with improved performance and lower land usage, developing new turbine products, and specialized power units designed to reduce fuel consumption and associated costs during a project s development phase.

Additionally, we are continuing to evaluate investment opportunities in new companies with product offerings for renewable energy markets, such as our investment in W&M, a company with whom we are engaged for the development of energy harvesting and system balancing solutions for electrical sources and, in particular, Solar PV.

Table of Contents

Market Opportunity

Interest in geothermal energy in the United States remains strong as a result of legislative and regulatory support for renewable energy, and the baseload nature of geothermal energy generation.

Although electricity generation from geothermal resources is currently concentrated mainly in California, Nevada, Hawaii, Idaho and Utah, there are opportunities for development in other states such as Alaska, Arizona, New Mexico, Washington and Oregon due to the availability of geothermal resources and, in some cases, a favorable regulatory environment in such states.

The Western Governors Association estimates that 13,000 MW of identified geothermal resources will be developed by 2025. In a report issued in April 2010 for the World Geothermal Congress, Ruggero Bertani of Enel Green Power forecasted that by 2015 the worldwide installed capacity will increase by approximately 73% from 10,715 MW in 2010 to 18,500 MW in 2015. The report identifies the U.S., Indonesia, the Philippines, New Zealand and Mexico as the main contributors to the forecasted growth.

In a report issued in April 2011, the Geothermal Energy Association identified a total of 146 confirmed and unconfirmed geothermal projects under various phases of consideration or development in 15 U.S. states that have between 4,448 MW and 5,040 MW potential capacity.

The assessments conducted by the Western Governors Association and the Geothermal Energy Association are estimates only. We refer to them only as two possible reference points, but we do not necessarily concur with those estimates.

An additional factor fueling recent growth in the renewable energy industry is global concern about the environment. Power plants that use fossil fuels generate higher levels of air pollution and their emissions have been linked to acid rain and global warming. 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 United States, Arizona, California, Colorado, Connecticut, Delaware, Hawaii, Illinois, Indiana, Iowa, Kansas, Maine, Maryland, Massachusetts, Michigan, Minnesota, Missouri, Montana, Nevada, New Hampshire, New Jersey, New Mexico, New York, North Carolina, North Dakota, Ohio, Oklahoma, Oregon, Pennsylvania, Rhode Island, South Dakota, Texas, Utah, Vermont, Virginia, Washington, West Virginia, Wisconsin and the District of Colombia have all 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.

According to the Database of State Incentives for Renewables and Efficiency (DSIRE), twenty nine states (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.

According to DSIRE, seventeen states have enacted RPS and Alternative Portfolio Standards that include some form of combined heat and power and/or waste heat recovery. The seventeen states are: Arizona, Colorado, Connecticut, Hawaii, Indiana, Maine, Michigan, Nevada, New York, North Carolina, North Dakota, Ohio, Pennsylvania, South Dakota, Utah, Washington, and West Virginia.

We believe that these legislative measures and initiatives present a significant market opportunity for us. In California, on April 12, 2011, Governor Jerry Brown signed Senate Bill X1-2 (SBX1-2) to increase California s RPS to 33% by December 31, 2020, among the most aggressive renewable energy goals in the United States. 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 increase in California s RPS, as one of the most significant opportunities for us to expand existing projects and build new power plants. In 2010, California s RPS target was to supply at least 20% of the total retail electricity sales from eligible renewable energy resources; California s three large investor-owned utilities collectively served 17% of their 2010 retail electricity sales with renewable

Table of Contents

power. Due to flexible compliance, California utilities must average 20% through years 2011-2013. The investor-owned utilities have interim targets each year, with a requirement of 25% by 2016. Due to the new 33% target, publicly-owned utilities in California must also procure 33% of retail electricity sales from eligible renewable energy resources by 2020, opening up a significant new market of potential off-takers in years ahead. These utilities do not have interim targets. Nevada s RPS requires NV Energy to supply at least 15% of the total electricity it sells from eligible renewable energy resources by 2013, which will increase to 25% by 2025. In 2010, 14.8% of the electricity retail sales in Nevada were from renewable energy sources. Hawaii s RPS requires each Hawaiian 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. In 2010, Hawaiian Electric Company and its subsidiaries achieved a consolidated RPS of 20.7%.

In 2006, California passed a state climate change law, AB 32. The goal of AB 32 is to reduce GHG emissions to 1990 levels by the end of 2020. In 2008, CARB approved a Scoping Plan to carry out regulations implementing AB 32. In December 2010, CARB approved cap-and-trade regulations to reduce California s GHG emissions under AB 32. The cap-and-trade regulation, the first phase of which was initiated in January 2012 with compliance obligations commencing in January 2013, will set a statewide limit on emissions from sources responsible for emitting 80% of California s GHGs and, according to CARB, will help establish a price signal needed to drive long-term investment in cleaner fuels and more efficient use of energy. However, implementation of this cap-and-trade program under AB 32 has been the subject of legal challenges that may hinder and/or ultimately thwart its implementation. At the federal level as of 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. 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. The first-in-the-nation auction of carbon dioxide allowances was held in September 2008. Under RGGI, the participating states plan to reduce carbon emissions from power plants by 10%, at a rate of 2.5% per year between 2015 and 2018.

In addition to RGGI, other states have also established the Midwestern Regional Greenhouse Gas Reduction Accord and 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.

The federal government also encourages production of electricity from geothermal resources through certain tax subsidies. We are permitted to claim 30% of certain eligible costs of a new geothermal power plant put into service prior to December 31, 2013 in the United States as a one-time credit against our federal income taxes. Projects put into service after that date continue to qualify, but the credit is reduced to 10% (certain tax benefits are impacted by these tax credits as described in the section below). Alternatively, we are permitted to claim a tax credit based on the power produced from a geothermal power plant. These production-based credits, which in 2011 were 2.2 cents per kWh, are adjusted annually for inflation and may be claimed for ten years on the electricity produced by a new geothermal power plant put into service prior to December 31, 2013. The production-based credits are allowed only to the extent the power is sold to a third party. The owner of the power plant must choose between these two types of tax credits described above. In either case, under current tax rules, any unused tax credit has a one-year carry back and a twenty-year carry forward. Another alternative available is a cash grant for Specified Energy Projects in Lieu of Tax Credits from the U.S. Treasury. It is available for certain power plants placed in service by the end of 2011, or on which construction began in 2009, 2010 or 2011 and that are completed by the end of 2013. Please refer to Item 7 Management s Discussion and Analysis of Financial Condition and Result of Operations regarding the valuation allowance we recorded in the year ended December 31, 2011 against deferred tax assets related to the abovementioned tax credits.

Table of Contents

Whether we claim tax credits or a cash grant, we are also permitted to depreciate, or write off, most of the cost of the plant. If we claim the one-time 30% (or 10%) tax credit or receive the ITC cash grant, our tax basis in the plant that we can recover through depreciation must be reduced by one-half of the tax credit or cash grant; if we claim other tax credits, there is no reduction in the tax basis for depreciation. For projects that we placed into service after September 8, 2010 and before January 1, 2012, a depreciation bonus will permit us to write off 100% of the cost of certain equipment that is part of the geothermal power plant in the year the plant is placed into service, if certain requirements are met. For projects that are placed into service after December 31, 2011 and before January 1, 2013, 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 fully utilized) have a present value equivalent to approximately 30% to 40% of the capital cost of a new power plant.

Production of electricity from geothermal resources may also be supported under the Temporary Program For Rapid Deployment of Renewable Energy and Electric Power Transmission Projects established with the DOE as part of the DOE s existing Innovative Technology Loan Guarantee Program. The Temporary Program (i) extends the scope of the existing federal loan guarantee program to cover renewable energy projects, renewable energy component manufacturing facilities and electricity transmission projects that embody established commercial, as well as innovative, technologies; and (ii) provides an appropriation to cover the credit subsidy cost of such projects (meaning estimated average costs to the federal government from issuing the loan guarantee, equivalent to a lending bank s loan loss reserve). Although the Temporary Program was subject to a September 30, 2011 sunset, Congress has enacted further authorizations and appropriations to provide for a limited amount of subsidized support beyond that date for projects that would have qualified for the Temporary Program. A project supported by the federal guarantee under the new program must pay prevailing federal wages.

Operations outside of the United States may be subject to and/or benefit from requirements under the Kyoto Protocol. In December 2011, the United Nations Climate Change Conference was held in Durban, South Africa. The conference encompassed the 17th Conference of the Parties to the United Nations Framework Convention on Climate Change and the seventh meeting of the Parties to the Kyoto Protocol. Negotiators agreed to start work on a new climate deal that would have legal force and, crucially, require both developed and developing countries to cut their carbon emissions. The terms now need to be agreed by 2015 and will come into effect from 2020. The next Conference of the Parties is scheduled to take place in Qatar in November 2012. Before the Qatar conference in November 2012, the Rio +20 United Nations Conference will take place in Rio de Janeiro in June 2012. The first Rio summit 20 years ago is seen as one of the most ambitious gatherings in the history of the United Nations. More than 100 heads of state signed up to a raft of actions, including efforts to halt the deterioration of the ozone layer, tackle climate change and reduce the loss of biodiversity. These issues have taken center stage in international negotiations over the past two decades.

Outside of the United States, 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 and have encouraged 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 countries have also adopted active governmental programs designed to encourage clean renewable energy power generation. Several Latin American countries have rural electrification programs and renewable energy programs. For example, Guatemala, where our Zunil and Amatitlan power plants are located, approved in November 2003 a law which created incentives for power generation from renewable energy sources by, 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. Another example is New Zealand, where we (and our Parent before us) have been actively designing and supplying geothermal power solutions since 1986. The New Zealand government s policies to fight climate change include a target for GHG emissions reductions 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. In Indonesia, the government has implemented policies and regulations intended to accelerate the development of renewable energy and geothermal projects in particular. These include 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 is IPP projects and the remaining state utility PLN projects. For the IPP sector, certain regulations for geothermal projects have been implemented providing for incentives such as investment tax credits and accelerated depreciation, and pricing guidelines intended to allow preferential power prices for generators; other regulation are being discussed. In addition, there is a regulation providing feed-in tariffs for small scale renewable energy projects up to 10 MW. 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 20% by 2020, which is intended to be achieved mainly through prevention of deforestation and accelerated renewable energy development. Another example is Chile, where we were recently awarded six exploration concessions. The Chilean Renewable Energy Act of 2008 requires that 5% of electricity sold come from renewable sources beginning in 2010, increasing gradually to 10% by 2024.

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.

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 may benefit from the increased attention to energy efficiency. For example, in the United States, 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 20 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, Colorado, Connecticut, Indiana, Louisiana, Michigan, Nevada, North Dakota, Ohio, Oklahoma, Pennsylvania, South Dakota, Utah, and West Virginia allow electric utilities to include recovered energy-based power generation in calculating their compliance with their mandatory or voluntary RPS. In addition, California recently 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 (whether in those two states or elsewhere in the United States) for federally funded, low interest loans, but currently do not qualify for an ITC, PTC, or ITC cash grant. 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.

The market for solar 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 in various regions with a view to developing Solar PV power plants in those locations where we can offer competitively priced power generation, particularly where we can develop a Solar PV plant next to one of our existing power plants, and thereby leverage existing infrastructure and otherwise take advantage of operating efficiencies.

Table of Contents

Competitive Strengths

Competitive Assets. 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.

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. We have a competitive advantage over other renewable energy sources, such as wind power, solar power or hydro-electric power (to the extent dependent on precipitation), which compete with us to meet electric utilities renewable portfolio requirements but which cannot serve baseload capacity because of their weather dependence and thus intermittent nature of these other renewable energy sources.

Competitive Pricing. Geothermal power plants, while site specific, are economically feasible to develop, construct, own, and operate in many locations, and the electricity they generate is generally price competitive compared to electricity generated from fossil fuels or other renewable sources under existing economic conditions and existing tax and regulatory regimes.

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 our exploration, development, and construction activities, to a certain level. We believe that this gives us a competitive advantage over certain competitors whose activities are more dependent on external credit and financing sources that may be subject to availability constraints depending on prevailing global credit and market conditions.

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.

We design, manufacture, and sell to third parties power units and other power generating equipment for geothermal and recovered energy-based electricity generation. Our extensive experience in the development of state-of-the-art, environmentally sound power solutions enables our customers to relatively easily finance their power plants.

Exploration and Drilling Capabilities. We have in-house capabilities to explore and develop geothermal resources. We have established a drilling subsidiary that currently owns nine drilling rigs. We employ an experienced resource group that includes engineers, geologists, and drillers. This resource group 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.

Table of Contents

Technological Innovation. We have been granted 82 U.S. patents (additionally approximately 20 patents are 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 and the drilling of wells is complete, 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 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;

Development and Construction of Recovered Energy Power Plants establishing a first-to-market leadership position in recovered energy power plants in North America and building on that experience to expand into other markets worldwide;

Acquisition of New Assets acquiring from third parties additional geothermal and other renewable assets that meet our investment criteria;

Manufacturing and Providing Products and Service 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; and

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

In addition, we are considering various opportunities in the solar energy market and recently commenced construction of the Heber Solar project in Imperial Valley, California. There are several reasons for entering the solar energy market including:

the recent decline in the cost of Solar PV technologies;

the attractive electricity prices that may be achieved in certain regions;

Table of Contents

- our ability to leverage EPC and development expertise in geothermal and recovered energy power generation facilities; and

- cost efficiencies we can derive from sharing infrastructure and related facilities, as well as operations and maintenance, with our existing power plants.

Among other things, we have considered, and expect to continue to consider, a number of different opportunities including:

- acquisitions and joint ventures;

- expanding our internal research and development activity, or acquiring other companies engaged in solar research and development activities; and

- constructing and operating solar electric power generation facilities.

Recent Developments

On February 16, 2012, Geothermal Development Company (GDC) that is owned by the Government of Kenya, has awarded our subsidiary the first well head power plant project in the Menengai geothermal field in Kenya on a Build-Own-Transfer basis. The award is the result of an international tender for the design, manufacturing, procurement, construction and commissioning of the 6 MW geothermal well head power plant. GDC will supply the steam for conversion to electricity by Ormat s power plant. The Menengai geothermal field is located on the outskirts of the town of Nakuru, about 180 kilometers west of Nairobi.

On January 30, 2012, the PUCN approved the 20-year PPA that we signed in February 2011 with NV Energy to sell 30 MW from the Dixie Meadows geothermal project that we are developing in Churchill County, Nevada.

In December 2011, the PUCH approved the 20-year PPA we signed in February 2011 with HELCO to sell to the Hawaii Island grid an additional 8 MW of dispatchable geothermal power. The power is generated from the Puna complex and is sold at a fixed price (subject to escalation) independent of oil prices. Further information on the terms of the PPA is described in Operation of our Electricity Segment under Puna Complex .

In December 2011, we signed a termination agreement with respect to the PPA and joint operating agreement with NV Energy for the Carson Lake geothermal project in Churchill County, Nevada. Further information is provided under Operation of our Electricity Segment under Carson Lake Project .

In December 2011, we signed a 20-year PPA with IID for 10 MW of Solar PV energy from a project located near the Heber geothermal complex in Imperial Valley, California. This will be our first utility- scale Solar PV project. Construction started in 2011 and commercial operation is expected within 18 months, subject to timely completion of the interconnection, for which IID is responsible.

On December 20, 2011, our subsidiary, Ormat Nevada signed a $21.4 million EPC contract and a credit agreement with Thermo No. 1 BE-01, LLC (Thermo I), a subsidiary of Cyrq Energy, Inc. (Cyrq), in connection with the construction of an OEC at Thermo I s existing geothermal power plant in Utah to increase the plant s output and reduce operating costs. Under the credit agreement, we will provide financing in an aggregate principal amount not to exceed $22.7 million that will be used to finance the project construction costs under the EPC contract with Thermo I. The project is expected to have a relatively short completion schedule and could come online by the middle of 2013.

On November 22, 2011, our subsidiary, Ormat Nevada, signed a $65.0 million EPC contract and a credit agreement with Lightning Dock Geothermal HI-01, LLC (LDG), a subsidiary of Cyrq, in connection with the construction of LDG s geothermal project in New Mexico. The EPC contract work is scheduled to be released in stages based on LDG s progress in the well field drilling and development necessary to support the project. Early engineering will be released as soon as the basic well field characteristics are confirmed in order to maintain the project schedule. Further work will be released based on the progress of the well field development. Under the credit agreement we will provide financing in an aggregate principal amount not to exceed $66.0 million that will be used to finance the project construction costs under the EPC contract with LDG. The project is expected to come online by the end of 2013.

In October 2011, the Chilean Committee on Geothermal Energy Analysis recommended that the Chilean Ministry of Energy award us five exploration concessions in Chile. Under the applicable regulatory framework governing the concessions, in order to maintain the development rights granted under these concessions, we will need to make certain investments in an exploration program over the next two years. Following compliance with these exploration commitments, we may receive an exploitation license, which is the first step toward power plant construction.

In September 2011, our wholly owned indirect subsidiary, OFC 2, and its project subsidiaries (the Issuers), finalized and signed loan documentation for a 20-year loan for up to $350.0 million aggregate principal amount of OFC 2 Senior Secured Notes due December 31, 2034 under a financing agreement with John Hancock. The transaction will be guaranteed by the DOE s Loan Programs Office in accordance with and subject to the DOE s Loan Guarantee Program under Section 1705 of Title XVII of the Energy Policy Act of 2005. The financing will support power generation from three Nevada-based facilities built in two phases that are expected to generate up to 113 MW of power. The three facilities, Jersey Valley, McGinness Hills, and Tuscarora, will provide baseload power through 20-year PPAs with Nevada Power Company, a subsidiary of NV Energy. The capacity of the first phase is expected to be up to approximately 60 MW. The second phase of development is subject to a feasibility assessment of the geothermal resource, which will be performed following completion of the first phase of each facility and fulfillment of other conditions in the loan documents. On October 31, 2011, OFC 2 and the Issuers completed the sale of $151.7 million aggregate principal amount of Series A of OFC 2 Senior Secured Notes due 2032. The net proceeds from the sale of the Series A of OFC 2 Senior Secured Notes, after deducting transaction fees and expenses, were approximately $141.1 million, and will be used to finance a portion of the construction costs of Phase I of the McGinness Hills and Tuscarora facilities.

In September 2011, our wholly owned subsidiary, Ormat International, signed a commitment letter with OPIC to provide project financing of up to $310.0 million to refinance and expand our 48 MW Olkaria III geothermal complex located in Naivasha, Kenya. Under the agreed term sheet attached to the commitment letter, the loan will be comprised of a refinancing tranche of up to $85.0 million to prepay the existing loan and fund transaction costs, a construction loan tranche of up to $165.0 million to finance the construction of an additional 36 MW expansion currently underway, and a $60.0 million stand-by facility to finance an additional optional 16 MW capacity expansion, that, if exercised by us, could bring the total capacity of the complex to approximately 100 MW. The maturity dates of the construction tranche and the refinancing tranche are expected to be June 2030 and December 2030, respectively. The maturity date and certain other terms of the stand-by facility will be finalized following our decision, if any, to exercise the option to construct the additional 16 MW expansion.

We have completed the modification of the 20 MW Burdette (Galena 1) power plant into an evaporative cooling configuration. Evaporative cooling provides increased power generation from air-cooled facilities, compared to regular air-cooled facilities by as much as 30% during the peak heat hours of the day. The implementation of this system in moderate to dry climates, especially in the high desert, generates more energy per year than water-cooled systems, and with a fraction of the water and chemical consumption of traditional water-cooled systems.

In June 2011, we signed a lease agreement for approximately 300 acres with Kibbutz Revivim in Israel. We plan to use the land to build a Solar PV power plant.

In June 2011, we entered into a BOT agreement with TGL to explore, develop, supply, construct, own and operate a geothermal power plant in the Tikitere geothermal area near Rotorua, New Zealand. Under the BOT agreement, the parties will jointly develop a geothermal power plant with an estimated capacity of approximately 45 MW. We will own and operate the project for an initial period of 14 years following

Table of Contents

commercial operation and then the ownership interests in the project will be transferred to TGL. The project will utilize Ormat s generating units. The BOT agreement is conditional upon receiving regulatory approval and resolution of internal arrangements, such as royalties, between the trusts owning the land. Construction of the power plant will commence following the obtaining of local permits, as well as satisfactory feasibility results following exploration and development activities to be carried out by us.

In June 2011, two of our subsidiaries signed a supply contract and an EPC contract with Mighty River Power Limited of New Zealand, for the first stage of the Ngatamariki geothermal project valued at a total of approximately $130.0 million. The new power plant is to be constructed on the Ngatamariki Geothermal Field in New Zealand. Construction of the power plant is expected to be completed within 24 months from the contract date. Mighty River Power Limited, a state-owned enterprise, is a New Zealand electricity generation and electricity retailing company.

In May 2011, we entered into a supply contract with Norske Skog Tasman Limited of New Zealand to supply a new geothermal power plant that is to be constructed in the Kawerau Geothermal Field in New Zealand. The contract is valued at a total of approximately $20.0 million and delivery of the power plant is expected to be completed within 13 months from the contract date.

In April 2011, we amended and restated the PPA with KPLC, the off-taker of the Olkaria III complex located in Naivasha, Kenya. The amended and restated PPA governs our construction of, and KPLC s purchase of electricity from, a new 36 MW power plant at the Olkaria III complex. The new power plant is scheduled to come online in 2013. The PPA amendment includes an option to increase the combined 84 MW capacity from the new and existing plants to a maximum of 100 MW, subject to monitoring and assessment of the geothermal reservoir capacity.

In March 2011, we entered into an agreement with the Weyerhaeuser Company granting us an option to enter into geothermal leases covering approximately 264,000 acres of land in Oregon and Washington. Under this agreement we have the exclusive right to explore the land for geothermal resources and may enter into one or more geothermal leases within the optioned land.

On March 31, 2011, Southern California Edison Company (Southern California Edison) set the demonstrated capacity of the North Brawley power plant at 33 MW. Southern California Edison also agreed to modify the North Brawley PPA to allow us the option of performing an additional capacity demonstration within one year from the first capacity demonstration on March 31, 2011, which may enable us to increase the demonstrated capacity of the plant.

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 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, particularly in Nevada. These activities generally involve:

Identifying and evaluating potential geothermal resources using information available to us from public and private resources as described under Initial Evaluation below.

- 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 described under Land Acquisition below.

- Conducting geophysical and geochemical surveys on some or all of the sites acquired, as described under Surveys below.

- Obtaining permits to conduct exploratory drilling, as described under Environmental Permits below.

- Drilling one or more exploratory wells on some or all of the sites to confirm and/or define the geothermal resource where indicated by our surveys, creating access roads to drilling locations and related activities, as described under Exploratory Drilling below.

- Drilling a full-size well (as described below) if our exploratory drilling indicates the geothermal resource can support a commercially viable power plant taking into account various factors described under Exploratory Drilling below. Drilling a full-size well is the point at which we usually consider a site moves from exploration to construction.

It normally takes us one to two 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.

Initial Evaluation. As part of our initial evaluation, we generally follow the following process, although our process can vary from site to site depending on the particular circumstances involved:

- We evaluate historic, geologic and geothermal information available from public and private databases.

- For some sites, we may obtain and evaluate additional information from other industry participants, such as where oil or gas wells may have been drilled on or near a site.

- We generally create a digital, spatial geographic information systems database containing all pertinent information, including thermal water temperature gradients derived from historic drilling, geologic mapping information (e.g., formations, structure 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 of a site range from approximately $20,000 to $100,000.

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

Land Acquisition. For domestic power plants, we either lease or own the sites on which our power plants are located. In 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 other agreement granting us the exclusive right to extract geothermal resources from specified areas of land, with the owners (or sublessors) of such land. This documentation will usually give 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 under the heading Description of Our Leases and Lands.

For most of our current exploration sites in Nevada, 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. There is a summary of our typical lease terms under the heading 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. Following the acquisition of land rights for a potential geothermal resource, we conduct surface water analyses and soil surveys to determine proximity to possible heat flow anomalies and up-flow/permeable zones and augment our digital database with the results of those analyses. We then initiate a suite of geophysical surveys (e.g., gravity, magnetics, resistivity, magnetotellurics, and spectral surveys) to assess surface and sub-surface structure (e.g., faults and fractures) and develop a roadmap of fluid-flow conduits and overall permeability. All pertinent geophysical data are then used to create three-dimensional geothermal reservoir models that are used to identify drill locations.

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 and geophysical surveys. If the results from the geochemical and geophysical surveys are poor (i.e., low derived resource temperatures or poor permeability), we will re-evaluate the commercial viability of the geothermal resource and may not proceed to exploratory drilling.

Exploratory Drilling. If we proceed to exploratory drilling, we generally will use outside contractors to create access roads to drilling sites. After obtaining drilling permits, we generally drill temperature gradient holes and/or slim holes using either our own drilling equipment or outside contractors. However, exploration of some geothermal resources can require drilling a full-size well, particularly where the resource is deep underground. If the slim hole is dry , it may be capped and the area reclaimed if we conclude that the geothermal resource will not support a commercially viable power project. If the slim hole supports a conclusion that the geothermal resource will support a commercially viable power plant, it may either be:

- Converted to a full-size commercial well, used either for extraction or reinjection of geothermal fluids (Production Well).
- Used as an observation well to monitor and define the geothermal resource.

The costs we incur for exploratory drilling vary from site to site based on various factors, including market demand for drilling contractors and equipment (which may be affected by on-shore oil and gas exploration activities, etc.), the accessibility of the drill site, the geology of the site, and the depth of the resource, among other things. However, on average, exploration drilling costs are approximately $5 million for each site.

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

- New information 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.

Table of Contents

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.

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. As noted above, we consider drilling the first Production Well as the beginning of our construction phase for a power plant. 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. The Production Wells are normally drilled by our own drilling equipment. In some cases we use outside contractors, generally firms that service the on-shore oil and gas industry.

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. On average, however, our costs for each Production Well range from $3 million to $5 million.

Design. We use our own employees to design the well field and the power plant, including equipment that we manufacture. 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 the heading Environmental Permits.

Manufacturing. Generally, we manufacture most of the power generating unit equipment we use at our power plants. Multiple sources of supply are 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.

Table of Contents

During the year ended December 31, 2011, one site (Olkaria III Phase III) moved to construction, and during each of the years ended December 31, 2010 and 2009, two sites moved to construction. In 2010 the sites were CD4 at the Mammoth complex and Wild Rose (formerly DH Wells), and in 2009, the sites were Carson Lake and McGinness Hills. During the years ended December 31, 2010 and 2009, we discontinued exploration activities at one site each year. Those sites were Gabbs Valley and Rock Hills, in Nevada. After conducting exploratory drilling in those sites, we concluded that the geothermal resource at those sites would not support commercially viable power plants at this time. The costs associated with exploration activities at those sites were expensed during the years ended December 31, 2010 and 2009, respectively, (see Write-off of Unsuccessful Exploration Activities under Item 7 Management Discussion and Analysis of Financial Condition and Results of Operations). Thirteen new sites were added to our exploration and development activities in the year ended December 31, 2011, compared with seven sites in the year ended December 31, 2010 and with six sites in the year ended December 31, 2009.

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 United States, 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. A power plant s revenues under a PPA used to consist of two payments energy payments and capacity payments; however 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, such as us) 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 a financing structure 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 the heading 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% to 90% of our revenue loss derived from a specified governmental act such as confiscation, expropriation, riots, the inability to convert local currency into hard currency, and, in certain cases, the breach of agreements. We have obtained such insurance for all of our foreign power plants in operation.

Description of Our Leases and Lands

We have domestic leases on approximately 481,000 acres of federal, state, and private land in California, Nevada, Utah, Alaska, Hawaii, Oregon, and Idaho. The approximate breakdown between federal, state, and private leases is as follows:

72% are leases with the U.S. government, acting through the BLM;

Table of Contents

15% are leases with various states, none of which is currently material; and

13% are leases with private landowners and/or leaseholders.

Each of the leases within each of the categories has standard terms and requirements, as summarized below. We own approximately 6,700 acres of land in Nevada and California. Internationally, our land position includes approximately 365,000 acres, most of which are geothermal exploration licenses in six prospects in Chile. In addition, we own land, a portion of which is used for our Heber Solar PV project.

Bureau of Land Management 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.

Table of Contents

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 1-2.5% 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% 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 reinject 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.

Table of Contents

Description of Our Power Plants

Domestic Power Plants

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

Brady Complex

Location	Churchill County, Nevada
Generating Capacity	25 MW
Number of Power Plants	2 (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 6 injection wells are connected to the plants through a gathering system.
Major Equipment	Three OEC units and three steam turbines along with 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 of mainly 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 278 degrees Fahrenheit and at Desert Peak 2 is 370 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.

Table of Contents

Resource Cooling	Approximately 4 degrees Fahrenheit per year was observed at Brady during the past 15 years of production. The temperature decline at Desert Peak is less than 1 degree 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 (Brady) and OPC Transaction (Desert Peak 2).

Heber Complex

Location	Heber, Imperial County, California
Generating Capacity	92 MW
Number of Power Plants	5 (Heber 1, Heber 2, Heber South, G-1 and G-2).
Technology	The Heber 1 plant utilizes dual flash and the Heber 2, Heber South, G-1 and G-2 plants 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 1 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 G-1 plant commenced commercial operation in 2006 and the G-2 plant in 2005. The Heber South plant commenced commercial operation in 2008.
Land and Mineral Rights	The total Heber area is comprised of mainly 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 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 350 degrees Fahrenheit. The resource supplying the pumped Heber 2 wells averages 318 degrees Fahrenheit.

Table of Contents

	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	1 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	2 PPAs with Southern California Edison and 1 PPA with SCPPA.
PPA Expiration Date	Heber 1 2015, Heber 2 2023, and Heber South 2031. The output from the G-1 and G-2 power plants is sold under the PPAs of Southern California Edison and SCPPA.
Financing	OrCal Senior Secured Notes.
Supplemental Information	As a result of the significant decrease in natural gas price forecasts for 2012 and 2013 and the delay of California s GHG cap-and-trade program that is now scheduled to begin in 2013, each of which is uncertain and subject to changes, we are currently looking at alternative contractual solutions to the PPAs. However, using the January 2012 estimates for gas prices in 2012 and 2013, it is expected that the new SRAC price formulas will reduce our revenues.
	We plan to enhance the complex and add 6 MW, if negotiation on new PPA will succeed.

Jersey Valley Power Plant

Location	Pershing County, Nevada
Generating Capacity	12 MW (See supplemental information below)
Number of Power Plants	1

Technology	The Jersey Valley power plant utilizes an air cooled binary system.
Subsurface Improvements	2 production wells and 4 injection wells are connected to the plant through a gathering system. The drilling of the third production well was completed and will be used in the future as required. Drilling of additional injection wells is currently under development.
Major Equipment	2 OEC units together with the Balance of Plant equipment.

Table of Contents

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 plants.
	The power plant 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 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 330 degrees Fahrenheit.	
Power Purchaser	Nevada Power Company.
PPA Expiration Date	January 1, 2032
Financing	Corporate funds.
	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.
	We have submitted an application for the ITC cash grant for the power plant.
Supplemental Information	The Jersey Valley power plant is currently operating below its designed capacity. This is primarily due to the need to shut down one of the injection wells that was rendered unusable by old mining wells that we believe were not adequately plugged when abandoned by the mining operator that previously operated on the land.
	We have drilled an additional injection well, which is being connected to the plant.

We have identified targets for additional wells and will continue to drill to improve injection capacity.

Mammoth Complex

Location	Mammoth Lakes, California

Table of Contents

Generating Capacity	29 MW
Number of Power Plants	3 (G-1, G-2, and G-3).
Technology	The Mammoth complex utilizes air cooled binary systems.
Subsurface Improvements	11 production wells and 5 injection wells connected to the plants through a gathering system.
Major Equipment	8 Rotoflow 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.
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 in Description of Our Leases and Lands.
	We recently purchased land at Mammoth that was owned by a third party. This purchase will reduce 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 (> 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	1 degree Fahrenheit per year was observed during the past 20 years of production.

Power Purchaser	Southern California Edison.
PPA Expiration Date	G-1 2014, G2 and G-3 2020.
Financing	50% OFC Senior Secured Notes and 50% corporate funds.

Table of Contents

Supplemental Information	As a result of the significant decrease in natural gas price forecasts for 2012 and 2013 and the delay of California s GHG cap-and-trade program that is now scheduled to begin in 2013, each of which is uncertain and subject to changes, we are currently looking at alternative contractual solutions to the PPAs. However, using the January 2012 estimates for gas prices in 2012 and 2013, it is expected that the new SRAC price formulas will reduce our revenues.
	We are in the process of repowering the Mammoth complex by replacing part of the old units with new Ormat-manufactured equipment. The replacement of the equipment will optimize generation and add approximately 3 MW of generating capacity to the complex.

North Brawley Power Plant

Location	Imperial County, California
Generating Capacity	33 MW (See supplemental information below)
Number of Power Plants	1
Technology	The North Brawley power plant utilizes a water-cooled binary system.
Subsurface Improvements	16 production wells and 21 injection wells are currently connected to the plant through a gathering system. An additional production well is currently being completed.
Major Equipment	5 OEC units together with the Balance of Plant equipment.
Age	The power plant was placed in service on January 15, 2010 with commercial operation having commenced 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 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 (1,500 4,500 feet) that was developed is fed by fractures and matrix permeability and is

42

	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.
Sources of Makeup Water	Water is provided by IID.
Power Purchaser	Southern California Edison
PPA Expiration Date	2031
Financing	Corporate funds and ITC cash grant from the U.S. Treasury.
Supplemental Information	The ramp up of the field has been slow and expensive. While we believe that the reservoir is large enough to support the originally designed generation capacity of 50 MW, the operation of the production wells, injection wells and the handling of the geothermal fluid has been a challenge.
	On March 31, 2011, Southern California Edison set the demonstrated capacity of the power plant at 33MW. Southern California Edison also agreed to modify the PPA to allow us the option of performing an additional capacity demonstration until March 31, 2012.
	There is ongoing work to increase the generation of the power plant. We have set new targets for production wells and identified improvements that we can make to the injection wells, all in parallel with our effort to reduce the operating expenses, mostly through modifications that would extend the service time of the production pumps.
	The power plant currently has an interim transmission agreement with IID. A transmission study that is in progress will allow IID to enter into a permanent transmission agreement. To date the study has been delayed due to extensive analysis by the utility and maintenance activity on the transmission corridor.

OREG 1 Power Plant

Location	Four gas compressor stations along the Northern Border natural gas pipeline in North and South Dakota

Generating Capacity	22 MW
Number of Units	4

43

Table of Contents

Technology	The OREG 1 power plant utilizes our air cooled OEC units.
Major Equipment	4 WHOH and 4 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.

OREG 2 Power Plant

Location	Four gas compressor stations along the Northern Border natural gas pipeline; one in Montana, two in North Dakota, and one in Minnesota
Generating Capacity	22 MW
Number of Units	4
Technology	The OREG 2 power plant utilizes our air cooled OEC units.
Major Equipment	4 WHOH and 4 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.

OREG 3 Power Plant

Location	A gas compressor station along Northern Border natural gas pipeline in Martin County, Minnesota
Generating Capacity	5.5 MW
Number of Units	1

Table of Contents

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.

OREG 4 Power Plant

Location	A gas compressor station along natural gas pipeline in Denver, Colorado
Generating Capacity	3.5 MW
Number of Units	1
Technology	The OREG 4 power plant utilizes our air cooled OEC units.
Major Equipment	2 WHOH and 1 OEC unit together with the Balance of Plant equipment.
Age	The OREG 4 power plant commenced commercial operations during 2009.
Land	Easement from Trailblazer Pipeline Company.
Access to Property	Direct access to the plant from public roads.
Power Purchaser	Highline Electric Association

PPA Expiration Date	2029
Financing	Corporate funds.

Ormesa Complex

Location	East Mesa, Imperial County, California
Generating Capacity	54 MW
Number of Power Plants	4 (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	32 production wells and 52 injection wells connected to the plants through a gathering system.
Material Major Equipment	32 OEC units and 2 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 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 307 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	1 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.
Supplemental Information	As a result of the significant decrease in natural gas price forecasts for 2012 and 2013 and the delay of California s GHG cap-and-trade program that is now scheduled to begin in 2013, each of which is uncertain and subject to changes, we are currently looking at

alternative contractual solutions to the PPAs. However, using the January 2012 estimates for gas prices in 2012 and 2013, it is expected that the new SRAC price formulas will reduce our revenues.

Table of Contents

Puna Complex

Location	Puna district, Big Island, Hawaii
Generating Capacity	38 MW
Number of Power Plants	2
Technology	The Puna plants utilize our geothermal combined cycle and binary systems. The plants use an air cooled system.
Subsurface Improvements	5 production wells and 4 injection wells connected to the plants through a gathering system. We are preparing to drill a sixth production well.
Major Equipment	One plant consists of 10 OEC units consisting of 10 binary turbines, 10 steam turbines and two bottoming units along with the Balance of Plant equipment. The second plant consists of 2 OEC units along with Balance of Plant equipment.
Age	The first plant commenced commercial operation in 1993. The second plant was placed in service in 2011, but has not yet reached commercial operation.
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 annual rental payment to KLP, which is adjusted every 5 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 3% 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	3 PPAs with HELCO (see Supplemental Information below).

Table of Contents

PPA Expiration Date	December 31, 2027.
Financing	Operating Lease.
	We have submitted an application for an ITC cash grant for the new 8 MW power plant.
Supplemental Information	The construction of the new 8 MW power plant has been completed and it was placed in service.
	We signed a new PPA with HELCO that was recently approved by the PUCH, under which the Puna power plant will deliver to the HELCO grid an additional dispatchable 8 MW and will revise the pricing for the energy that is sold from the Puna complex 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.

Steamboat Complex

Location	Steamboat, Washoe County, Nevada
Generating Capacity	86 MW
Number of Power Plants	7 (Steamboat 1A, 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	23 production wells and 8 injection wells connected to the plants through a gathering system.

Table of Contents

Major Equipment	12 individual air cooled OEC units and one steam turbine together with the Balance of Plant equipment.
Age	The Steamboat 1A plant commenced commercial operation in 1988 and the other 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 and we repowered Steamboat 1A.
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 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 292 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.
	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	2 degrees Fahrenheit per year was observed during the past 20 years of production.
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 1A, Steamboat 2 and 3, Burdette, Steamboat Hills, and Galena 3) and Nevada Power Company (for Galena 2).
PPA Expiration Date	Steamboat 1A 2018, Steamboat 2 and 3 2022, Burdette 2026, Steamboat Hills 2018, Galena 3 2028, and Galena 2 2027.

Table of Contents

Financing	OFC Senior Secured Notes (Steamboat 1A, Steamboat 2 and 3, and Burdette) and OPC Transaction (Steamboat Hills, Galena 2, and Galena 3).

Tuscarora Power Plant

Location	Elko County, Nevada
Projected Generating Capacity	18 MW
Number of Power Plants	1
Technology	The Tuscarora power plant utilizes a water cooled binary system.
Subsurface Improvements	3 production and 5 injection wells are connected to the power plant. A fourth production well is under development.
Major Equipment	2 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 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 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 346 degrees Fahrenheit.
Resource Cooling	Will be established in the future.

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 two water makeup wells. A third makeup well will be added.
Power Purchaser	Nevada Power Company

Table of Contents

PPA Expiration Date	2032
Financing	OFC 2 Senior Secured Notes.
	We plan to file an application for an ITC cash grant for the power plant.

Foreign Power Plants

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

Amatitlan Power Plant (Guatemala)

Location	Amatitlan, Guatemala
Generating Capacity	18 MW
Number of Power Plants	1
Technology	The Amatitlan power plant utilizes an air cooled binary system and a small back pressure steam turbine (1MW).
Subsurface Improvements	5 production wells and 2 injection wells connected to the plants through a gathering system.
Major Equipment	1 steam turbine and 2 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 3% the of concession area. Under the agreement with INDE, the power plant company pays royalties of 3.5% of revenues up to 20.5 MW and 2% 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 530 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 2 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.

Table of Contents

Power Purchasers	INDE and another local purchaser.
PPA Expiration Date	Contract with INDE expires in 2028.
Financing	Senior secured project loan from TCW Global Project Fund II, Ltd.
Supplemental Information	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.
	The power plant has a long-term contract to sell all of its emission reduction credits to a European buyer.

Momotombo Power Plant (Nicaragua)

Location	Momotombo, Nicaragua
Generating Capacity	22 MW
Number of Power Plants	1
Technology	The Momotombo power plant utilizes single flash and binary systems. The plant uses air and water cooled systems.
Subsurface Improvements	10 production wells and 7 injection wells connected to the plants through a gathering system.
Major Equipment	1 steam turbine and 1 OEC unit together with the Balance of Plant equipment.
Age	The plant commenced commercial operation in 1983 and was already in existence when we signed the concession agreement in 1999.
Land and Mineral Rights	The total Momotombo area is under a concession agreement which expires in 2014.
	We sell the generated electricity at the boundary of the plant. The transmission line is owned by the utility.
Resource Information	The resource temperature is an average of 466.5 degrees Fahrenheit.

	The Momotombo geothermal reservoir is located within sedimentary and andesitic volcanic formations that relate to the Momotombo volcano.
	Main flow paths in the geothermal system are a hot reservoir layer. The shallow layer conducted deep fluids that eventually will be discharged at surface at the eastern edge of the geothermal system at the shore of the Lake Managua.
Resource Cooling	Approximately 3.5 degrees Fahrenheit per year was observed during the past 10 years of production.

52

Access to Property	Direct access to public roads and access across the property are provided under surface rights granted pursuant to the concession assignment agreement.
Sources of Makeup Water	Condensed steam is used for makeup water.
Power Purchaser	DISNORTE and DISSUR
PPA Expiration Date	2014
Financing	A loan from Bank Hapoalim B.M, which was repaid in full in 2010.

Olkaria III Complex (Kenya)

Location	Naivasha, Kenya
Generating Capacity	52 MW
Number of Power Plants	2 (Olkaria III Phase 1 and Olkaria III Phase 2).
Technology	The Olkaria III complex utilizes an air cooled binary system.
Subsurface Improvements	10 production wells and 3 injection wells connected to the plants through a gathering system.
Major Equipment	6 OEC units together with the Balance of Plant equipment.
Age	Phase I plant commenced commercial operation in 2000 and was incorporated into the phase II plant in January 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.

Table of Contents

	Hot geothermal fluids rise up from deep in the northeastern portion of the concession area, penetrating a low permeability zone below 3280 feet ASL 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	2029
Financing	Senior secured project finance loan from a group of European DFIs.
Supplemental Information	See Projects under Construction Olkaria III Phase III (Kenya).
	We have signed a commitment letter issued by OPIC to provide up to $310 million to refinance and expand the Olkaria III complex. See New Financing of our Project in Item 7.
	If the Phase III of Olkaria III is completed by November 2015, the expiration date of the PPA will be extended until 2033.

Zunil Power Plant (Guatemala)

Location	Zunil, Guatemala
Generating Capacity	24 MW
Number of Power Plants	1
Technology	The Zunil power plant utilizes an air cooled binary system.
Major Equipment	7 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.
Access to Property	Direct access to public roads.
Power Purchaser	INDE

Table of Contents

PPA Expiration Date	2019
Financing	Senior Secured project loan from IFC and CDC that was repaid in full in November 2011.
Supplemental Information	Through August 2011, the energy output of the power plant was sold under a take or pay arrangement, under which the revenues were calculated based on 24 MW capacity regardless of the actual performance of the power plant. From September 2011, the energy portion of revenues is paid based on the actual generation of the power plant, while the capacity portion remains the same. The actual generation of the power plant is based on a capacity of approximately 13 MW. In 2011, the energy revenues were approximately 21% of the total revenues of the power plant**.**

Projects under Construction

We are in varying stages of construction or enhancement of domestic and foreign projects. Based on our current construction schedule, we have new generating capacity of approximately 145 MW under construction in California, Nevada, and Hawaii (including Mammoth expansion described above).

The following is a description of the projects currently undergoing 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	Received the approval of the BLM for the required EIS and for the permitting required to start the drilling of additional wells.
Subsurface Improvements	Awaiting drilling permits.
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 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 in Description of Our Leases and Lands.
Resource Information	The expected average temperature of the resource cannot be estimated as field development has not been completed yet.
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.

55

Table of Contents

Financing	Corporate funds.
Projected Operation	To be determined.
Supplemental Information	Permitting delays have prevented substantial progress on the project site and on transmission until late last year and have had a significant impact on the development plan and the economics of the project. As a result, in December 2011, we terminated the project s PPA and joint operating agreement with NV Energy. We are continuing to work on the project.

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	Drilling activity.
Subsurface Improvements	We have completed 1 production well and 1 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, several of which are held by production and the remainder of which are the subject of a unitization agreement that is pending BLM approval. The expiration date of the leases (assuming approval of the unitization agreement) is after the end of the expected useful life of the power plant.
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 to deliver energy into the Southern California Edison system at the Casa Diablo Substation.

56

Table of Contents

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	Procurement.
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	2013
Supplemental Information	Commercial operation is expected within 18 months from the signing of the PPA, subject to timely completion of the interconnection that is to be provided by IID.

McGinness Hills Project (U.S.)

Location	Lander County, Nevada
Projected Generating Capacity	30 MW
Projected Technology	The McGinness Hills power plant will utilize an air cooled binary system.
Subsurface Improvements	5 production wells and 3 injection wells have been drilled.

Material Equipment	Power plant equipment on site.
Condition	Field development is still in process and construction is in an advanced stage.
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 in Description of Our Leases and Lands.
	Unless steam is produced in commercial quantities, the primary term for these leases will expire commencing September 30, 2017.
	The project 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.

57

Table of Contents

Resource Information	The expected average temperature of the resource cannot be estimated as field development has not been completed yet.
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	20 years after date of COD.
Financing	OFC 2 Senior Secured Notes.
	We plan to file an application for an ITC cash grant for the project.
Projected Operation	Third quarter of 2012.
Supplemental Information	Commercial operation of the power plant is expected in the second half of 2012.

Olkaria III   Phase III (Kenya)

Location	Naivasha, Kenya
Projected Generating Capacity	36 MW
Technology	The phase III of the Olkaria III complex will utilize an air cooled binary system.
Condition	Field development and manufacturing of the power plant is in progress.
Subsurface Improvement	Two production wells have been drilled.
Land and Mineral Rights	The total Olkaria III area is comprised of government leases. See description above under Olkaria III complex.
Resource Information	The Olkaria III geothermal field is on the west side of the greater Olkaria geothermal area located within the Rift Valley at approximately 6,890 feet above sea level.

	Hot geothermal fluids rise up from deep in the northeastern portion of the concession area through low permeability at a shallow depth to a high productivity two-phase region from 3,280 to 4,270 feet above sea level.
	The expected average temperature of the resource cannot be estimated as field development has not been completed yet.
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.

Table of Contents

Power Purchaser	KPLC
PPA Expiration Date	20 years from COD.
Financing	Corporate funds.
Projected Operation	2013
Supplemental Information	We amended and restated the existing PPA with KPLC. The amended and restated PPA provides for the construction of a new 36 MW power plant at the Olkaria III complex. The PPA amendment includes an option for additional capacity up to 100 MW.
	We have signed a commitment letter with OPIC to provide up to $310 million to refinance and expand the Olkaria III complex. See description in Item 7 under New Financing of our Projects.

Wild Rose (formerly DH Wells) Project (U.S.)

Location	Mineral County, Nevada
Projected Generating Capacity	15-20 MW
Projected Technology	The Wild Rose power plant will utilize a binary system.
Material Equipment	Drilling equipment for wells.
Condition	Field development is in progress.
Subsurface Improvement	3 wells have been drilled. We are continuing with the drilling activity.
Land and Mineral Rights	The Wild Rose area is comprised of BLM leases.
	The leases are currently held by the payment of annual rental payments, as described in Description of Our Leases and Lands.
	Unless steam is produced in commercial quantities, the primary term for these leases will expire commencing September 30, 2017.

	The project 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.
Resource Information	The expected average temperature of the resource cannot be estimated as field development has not been completed yet.
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	We have not executed a PPA yet for this power plant.
Financing	Corporate funds.
Projected Operation	2013

Table of Contents

Projects under Exploration and Development and Future Projects

We also have other projects under various stages of development in the United States, Guatemala, Chile, 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 approximately 87 MW and our share in the combined generating capacity of the Solar PV projects would be 130 MW.

Crump Geyser Project (U.S.)

In October 2010, we and 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 NGP.

We will be the EPC contractor for the project, which 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.

We and NGP intend to build an up to 20 MW power plant, which is expected to be placed in service gradually.

Solar PV Projects (Israel)

We are currently in the process of developing ground-mounted and roof-top Solar PV projects in Israel under two joint venture agreements with Solar Hybrid Israel Ltd., which acquired the equity ownership in the joint venture from Sunday Energy. Under the ground-mounted joint venture agreement, we plan to build six projects with a total capacity of 38 MW. Our share in these projects will be 70%. Under the roof-top joint venture agreement, we plan to build eight projects with a total capacity of 18 MW. Our share in these projects will be 51%.

Additionally, we are a party to a joint venture agreement with Summit Holdings Real Estate Ltd. to develop 127 MW of utility scale ground-mounted Solar PV project located over three sites. Summit Holdings Real Estate Ltd. recently purchased Sunday Energy s interest in these projects. Our share in these projects will be 51%. We are also independently developing a 30 MW utility scale ground-mounted Solar PV project.

We have completed feasibility studies for all of these projects as required by the Israel Electric Corporation Ltd and we have submitted applications to obtain conditional licenses for these projects from the PUA; we have already received two such licenses. We believe that the installation permitting process for the ground-mounted projects will take longer to complete because of the zoning changes required for the land, compared to the permitting process for the roof-top projects, which do not require zoning changes. We estimate that only a portion of the above projects will be constructed.

In addition to the projects mentioned above, we are developing and are in the permitting phase for a roof-top Solar PV installation on our manufacturing facility in Yavne.

Sarulla Project (Indonesia)

We are a member of a consortium which is in the process of developing a geothermal power project in Indonesia of approximately 330 MW. We own 12.75% of the Indonesian special purpose entity that will operate the project.

Table of Contents

The project, located in Tapanuli Utara, North Sumatra, represents the largest single-contract geothermal power project to date, and reflects the large scale, high productivity and potential of Indonesian geothermal resources. The project will be owned and operated by the consortium members under the framework of a Joint Operating Contract (JOC) with PT Pertamina Geothermal Energy, and is to be constructed in three phases over four years, with each phase utilizing Ormat s 110 MW to 120 MW combined cycle geothermal plants.

The adjustment of the electricity tariff for the 330 MW Sarulla project has been agreed in principle between PLN (the state electric utility which is the off-taker of the electricity from the Sarulla Project) and the consortium, based on the verification of the agreed tariff by the BPKP (Indonesian State Auditor for Development). The JOC and the Energy Sales Contract (ESC) are currently in their final stage of being amended to reflect the agreed adjusted tariff as well as other financial conditions that have been agreed in principle by the relevant Indonesian ministries such as the Ministry of Energy and Mineral Resources and the Ministry of Finance. The execution of these amended contracts is expected to occur during the first half of 2012.

Sarulla Operations Ltd. (the project company) has received responses from over ten international banks that were invited to submit proposals to provide limited recourse financing for the Sarulla Project. The expected financing package will consist of direct loans from the Japan Bank for International Cooperation (JBIC) and the Asian Development Bank (ADB), plus Extended Political Risk Guarantees to the participating banks by JBIC. Sarulla Operations Ltd. has mandated certain lenders and the selection and engagement of due diligence consultants is currently underway.

Based on past experience, we find it difficult to estimate when these negotiations will be concluded. Construction is expected to start after the consortium obtains financing, a process which we expect to take approximately one year from the date of execution of the amended ESC and JOC.

Wister Project (U.S.)

We are currently developing the Wister project on private leases located in Imperial County, California. We expect the first phase of the project to be 30 MW.

The project has been awarded an exploration grant of $4.5 million under the DOE s Innovative Exploration and Drilling Projects program and the exploration activity under this program has started.

Others

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:

1. Various leases and concessions for geothermal resources of approximately 339,000 acres in 32 prospects including the following:

Nevada

Beowawe	Lease acquired but no further action has yet been taken.
Dixie Hope	Started exploratory drilling.
Dixie Meadows-Comstock	Completed exploration studies and are awaiting permits to start exploratory drilling at the site.
Edwards Creek	Started exploratory drilling.

Hyder Hot Springs/Dixie Valley	Lease acquired but no further action has yet been taken.
Leach Hot Springs	Started exploratory drilling.

61

Table of Contents

Seven Devils	Lease acquired but no further action has yet been taken.
Smith Creek	Under exploration studies.
Tungsten Mountain	Started exploratory drilling.
Tuscarora Expansion	Under exploration studies.
Wildhorse (Mustang)	Under exploration studies.
Quieta	Under exploration studies.
Argenta	Under exploration studies.
Hycroft	Under exploration studies.
Baltazar	Lease acquired but no further action has yet been taken.
South Jersey	Lease acquired but no further action has yet been taken.
California	
East & North Brawley	Deep resource lease acquired but no further action has yet been taken.
Rhyolite Plateau	Lease acquired but no further action has yet been taken.
Hawaii	
Ulupalakua (Maui)	Advanced exploration studies and the project has been awarded an exploration grant of $4.9 million under the DOE s Innovative Exploration and Drilling Projects program.
Kula	Under exploration studies.
Kona	Under exploration studies.
Oregon	

Glass Buttes Mahogany	Completed exploration studies and the project has been awarded an exploration grant of $4.3 million under the DOE s Innovative Exploration and Drilling Projects program. Awaiting permits to start exploratory drilling.
Glass Buttes Midnight Point	Completed exploration studies and are expected to start exploratory drilling
Newberry Twilight	Completed exploration studies and are expected to start exploratory drilling
Lakeview/Goose Lake-	Started exploration studies.
Idaho	
Magic Reservoir	Lease acquired but no further action has yet been taken.
Alaska	
Mount Spurr	Performed exploration drilling at the site and a $2.0 million exploration grant has been awarded.
Utah	
Drum Mountain	Under exploration studies.
Whirlwind Valley	Under exploration studies.

Table of Contents

Guatemala

Amatitlan Phase II	Started exploration studies.
Tecumburu	Surface rights have been obtained but no further action has yet been taken.

New Zealand

Tikitere	Started exploration studies.

2. *Exploration concessions for geothermal resources of approximately 336,000 acres in the following prospects:*

Chile

San Pablo	Exploration Concession has been approved; started exploration studies.
Aroma	Exploration Concession has been approved but no further action has yet been taken.
Mariman	Exploration Concession has been approved but no further action has yet been taken.
Quinohuen	Exploration Concession has been approved but no further action has yet been taken.
San Jose II	Exploration Concession has been approved but no further action has yet been taken.
Sollipulli.	Exploration Concession has been approved but no further action has yet been taken.

3. *We have an option to enter into geothermal leases covering more than 264,000 acres under a lease option agreement with Weyerhaeuser Company. We are currently exploring the following prospects:*

Oregon

Foley Hot Springs	Started exploration studies.
Silver Lake	Started exploration studies.
Summer Lake	Started exploration studies.

Nevada

Walker River Paiute	Started exploration studies. (option agreement under negotiation)

4. In addition to the geothermal resources listed above, we have leases pending for approximately 6,700 acres.

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

Table of Contents

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 at times 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, such as our PPA with Great River Energy for power from our REG facility on the Northern Border natural gas pipeline.

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. The Neptune recovered energy project is an example of this model. There, we installed one of our recovered energy-based generation units at Enterprise Product s Neptune gas processing plant in Louisiana. The unit utilizes exhaust gas from two gas turbines at the plant and is providing electrical power that is consumed internally by the facility (although a portion of the generated electricity is also sold to the local electric utility).

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 climate conditions, whether hot or cold. 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, from time to time, enter 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.

Table of Contents

Backlog

We have a product backlog of approximately $241 million as of February 15, 2012, which includes revenues for the period between January 1, 2012 and February 15, 2012, compared to $51.0 million as of February 15, 2011. The approximately $241 million includes: (i) an EPC contract in the amount of $21 million related to the Thermo 1 project with Cyrq, for which revenue will be recognized when payment by the customer is reasonably assured; and (ii) $27 million related to a geothermal supply contract, which is subject to the customer finalizing its financing arrangements for the project. The backlog does not include an EPC contact in the amount of $65 million related to the Lightning Dock Geothermal project with Cyrq.

The following is a breakdown of the Product Segment backlog as of February 15, 2012 (in millions):

	Expected Completion of the Contract	Sales Expected to be Recognized in 2012	Sales Expected to be Recognized in the years following 2012	Expected Until End of Contract
Geothermal	2013	$ 153	$ 70	$ 223
Recovered Energy	2012	6		6
Remote Power Units	2012	7		7
Other	2014	1	4	5
Total		**$ 167**	**$ 74**	**$ 241**

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

Our main competitors among geothermal power plant owners and developers in the United States are CalEnergy, Calpine, Terra-Gen Power LLC, ENEL SpA and other smaller-sized pure play developers. Outside the United States we face competition from some of the same geothermal power plant owners and developers in addition to other companies such as Chevron Corporation, Energy Development Corporation in the Philippines, developers such as Star Energy and Medco Energi in Indonesia, Mighty River Power and Contact Energy in New Zealand and Enel Colbus S.A. and others in Chile. We may also face competition from national electric utilities or state-owned oil companies.

Our competitors among renewable energy providers include companies engaged in the power generation business from renewable energy sources other than geothermal energy, 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. However, current demand for renewable energy is large enough that this increased competition has not materially impacted our ability to obtain new PPAs although we are starting to see signs that we might face a change where there will be competition from wind and more so from solar energy projects.

In the U.S., the Solar PV market is characterized by strong competition and low prices. We are focused on niche markets where our site-specific advantages can allow us to develop competitive projects. In Israel, the Solar PV market is based on a feed-in-tariff system creating a market that is driven less by price competitiveness and more by competition for land and for limited availability of electricity licenses.

Product Segment

Our competitors among power plant equipment suppliers are divided into two groups: high enthalpy and low enthalpy competitors. The main high enthalpy competitors are industrial turbine manufacturers such as Mitsubishi, Fuji and Toshiba of Japan, GE/Nuovo Pignone 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 of Japan, Mafi Trench, Atlas Copco Company, GE-Nuovo Pignone of Italy, and Turboden, a Pratt & Whitney Power Systems company (a unit of United Technologies Company), or systems integrators such as Turbine Air Systems and Geothermal Development Associates (GDA) of the U.S.

In the REG business, our competitors are other Organic Rankine Cycle manufacturers (such as GE and Turboden), manufactures that use Kalina technology (such as Siemens AG of Germany), as well as other manufacturers of conventional steam turbines. We believe that our REG system has technological and economic advantages over the products offered by the above mentioned companies, depending on the heat source conditions.

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 both in the sale of electricity and in the product business. Our competitors in the electricity segment are from time to time and in different jurisdictions our customers in the product segment.

When the proposed project is an EPC project we also compete with other service suppliers, such as project/engineering companies.

Customers

Most of our revenues from the sale of electricity in the year ended December 31, 2011 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 27.7%, 13.0%, 10.6% and 1.9% of revenues, respectively, for the year ended December 31, 2011. Based on publicly available information, as of December 31, 2011, 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 (stable outlook)
HELCO	BBB- (stable outlook)	Baa1
Sierra Pacific Power Company	BB+ (stable outlook)	Ba1 (stable outlook)
Nevada Power Company	BB+ (stable outlook)	Ba1 (stable outlook)
SCPPA	BBB (Outlook Developing)	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 business are derived from contractors or owners or operators of power plants, process companies, and pipelines, none of which traditionally account for more than 10% of our Product Segment revenues.

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, 2011, we employed 1,226 employees, of which 526 were located in the United States, 540 were located in Israel and 160 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 (other than the employees at the Momotombo power plant) 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.

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 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, insurance for work-related accidents, procedures for dismissing employees, annual and other vacation, sick pay, 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 insurance and such other 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 the Multilateral Investment Guarantee Agency (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

Table of Contents

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 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 megawatts; (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.

PURPA exempts Qualifying Facilities from regulation under the PUHCA 2005 and exempts Qualifying Facilities from most provisions of the FPA and state laws relating to the financial, organization and rate regulation of electric utilities. In addition, FERC s regulations promulgated 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).

Following passage of the Energy Policy Act of 2005, FERC issued a final rule that requires small power Qualifying Facilities to obtain market-based rate authority pursuant to the FPA for sales of energy or capacity from 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 Qualifying Facilities that are larger than 20 MW in size that seek to engage in non-PURPA sales of power (i.e., power that is sold in a manner that is not pursuant to a pre-existing contract or state implementation of PURPA) to obtain market-based rate authority from FERC for these non-PURPA sales. 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, the Qualifying Facility will not be required to file for market based rates.

The Energy Policy Act of 2005 also allows FERC 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

Table of Contents

(i) and (ii) above. FERC issued a rule to implement these provisions of the Energy Policy Act of 2005. This rule gives utilities the right to apply to eliminate the mandatory purchase obligation. The rule also creates a rebuttable presumption that a utility provides nondiscriminatory access if it has an open access transmission tariff in compliance with FERC s pro forma open access transmission tariff. Further, the rule provides a procedure for utilities that are not members of the four named regional transmission organizations to file to obtain relief from the mandatory purchase obligation on a service territory-wide basis, and establishes procedures for affected Qualifying Facilities to seek reinstatement of the purchase obligation. The rule protects 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. The FERC recently 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.

In addition, the Energy Policy Act of 2005 eliminated the restriction on utility ownership of a Qualifying Facility. Prior to the Energy Policy Act of 2005, electric utilities or electric utility holding companies could not own more than a 50% equity interest in a Qualifying Facility. Under the Energy Policy Act of 2005, electric utilities or holding companies may own up to 100% of the equity interest in a Qualifying Facility.

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 an elimination of the mandatory-purchase obligation in their service territories. 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

PUHCA was repealed, effective February 8, 2006, pursuant to the Energy Policy Act of 2005. Although PUHCA was repealed, the Energy Policy Act of 2005 created the new PUHCA 2005. 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 rate-making jurisdiction over 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. Qualifying Facilities are exempt from most 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

Table of Contents

flexibility. Even if a power plant does not lose Qualifying Facility status, if a PPA with a power plant is terminated or otherwise expires, 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 appropriate 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 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 and may be required to obtain groundwater permits in California to use groundwater resources for makeup water. 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 or other penalties.

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 remediation activities associated with a spill or release of such materials could be significant.

Table of Contents

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 and should not be considered a full statement of the laws in such countries or all of the issues pertaining thereto.

Nicaragua. In 1998, two laws were approved by Nicaraguan authorities, Law No. 272-98 and Law No. 271-98, which define the structure of the energy sector in the country. Law No. 272-98 provides for the establishment of the CNE, which is responsible for setting policies, strategies and objectives as well as approving indicative plans for the energy sector. Law No. 271-98 formally assigned regulatory, supervisory, inspection and oversight functions to the INE.

In 2002, the National Congress enacted Law No. 443 to regulate the granting of exploration and exploitation concessions for geothermal fields. The INE adopted this law.

In 2007, Nicaragua passed Law No. 612 amending Law No. 290, which governs the organization of the executive branch. Among other matters, the new law established a new ministry of energy and mining, which has assumed all of the functions and responsibilities of the CNE. The new Ministry of Energy and Mining is responsible for administrating Law No. 443 described above, and is also responsible for granting concessions and permits relating to the exploration or exploitation of any energy source, as well as concessions and licensing for generation, transmission, and distribution of energy.

The Nicaraguan energy sector has been restructured and partially privatized. Following such restructuring and privatization, the government retained title and control of the transmission assets and created the ENATREL, which is in charge of the operation of the transmission system in the country and of the new wholesale market. As part of the restructuring, most of the distribution facilities previously owned by the Nicaraguan Electricity Company, the government-owned vertically-integrated monopoly, were transferred to two companies, DISNORTE and DISSUR, which in turn were privatized and acquired by an affiliate of Union Fenosa, a large Spanish utility. Following such privatization, the PPA for our Momotombo power plant was assigned by the Nicaraguan Electricity Company to DISNORTE and DISSUR. In addition, a National Dispatch Center was created to work with ENATREL and provide for dispatch and wholesale market administration.

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.

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, the formulation of energy policy and the regulation of the energy sector remains vested in the national government (and not at the regional or local level where individual power plants may be located).

Regulation of Solar PV in Israel

The PUA published on December 12, 2009 regulations for medium-size Solar PV power systems that are larger than 50 kW. According to the regulations, the installed capacity of a medium-sized Solar PV system may not exceed the feasible connection to the distribution network.

The PUA approved a feed-in-tariff for medium-sized power systems. This feed-in-tariff is available for up to 300 MW of medium-sized power systems initiated prior to an expiry date in 2017. Rates under the feed-in-tariff are guaranteed for 20 years.

The feed-in-tariff rates awarded to a new project are set based on the year in which the PUA s tariff approval of such project is obtained. If the capacity cap in a certain year is met, projects in excess of the cap will be awarded the feed-in-tariff for the following year. On December 13, 2011, the PUA amended the feed-in-tariff rates to reflect reduced global Solar PV prices. The current feed-in-tariff rates are shown in the table below.

Year	Annual Cap (in MW)	Cumulative Cap (in MW)	Rate* (Cent/kWh)
2010-2011	50	50	39
2012	65	115	29
2013	85	200	27
2014-2017	100	300	25

* Based on an exchange rate of the NIS/dollar as of December 31, 2011 ($1 = NIS 3.821)

The PUA published on December 12, 2009 regulations for utility-scale Solar PV power systems above 12 MW that will be connected to the transmission system. Based on the December 31, 2011 exchange rate, the feed-in-tariff, 26 cents/kWh, is valid until 2015 after which the rate will drop by 10%. The quota for this rate is 200 MW and it is valid so long as project proponents reach financial closing by December 31, 2013.

Table of Contents

The licensing process designed by the PUA includes several stages. Developers that are interested in applying for a production license are required at the first stage to obtain a temporary license that will be given to candidates who can demonstrate they meet the following requirements:

- Proven land rights: for private lands, a signed option agreement between the candidate and the land-rights owner. If the land is owned by the ILA, the candidate must have a signed agreement with the land-rights owner, in addition to an ILA land-rights preference.

- Adequate financial resources: the candidate must demonstrate that it has equity in an amount equal to 20% of the normative cost to build a power plant, which is estimated by the PUA at $3.7 million per installed MW.

- Feasibility study completed by the Israel Electric Corporation Ltd. that demonstrates that the power plant can connect to the grid in accordance with the capacity demand (this requirement applies only to facilities with a capacity higher than 630kVA which will be connected to the high voltage grid).

- Appropriate experience and capabilities for design, construction and operation of high voltage power plants according to the power plant size declared in the temporary license.

A request that demonstrates compliance with the above requirements will be reviewed by PUA staff and will require the approval of the PUA plenum, followed by the approval of the Israeli Ministry of Energy and Water Resources.

Upon the signature of the conditional license by the Israeli Ministry of Energy and Water Resources, the developer of a facility with a capacity higher than 1 MW must provide the PUA with a bank guarantee in an amount equal to $1.80 per installed kW. In the event the developer subsequently fails to meet the milestones specified in the conditional license for financial closing, the PUA may draw up to 35% of the bank guarantee.

A developer that receives a conditional license will have 42 months to obtain all required permits to operate the power plant and attain a production license.

In December 2010, the National Planning Council of the Israeli Ministry of the Interior issued regulations for the development of solar installations in Israel.The regulations include guidelines for the statutory planning route for the development of Solar PV projects on agricultural and nonagricultural land. Following statutory approval, a developer who meets the milestones set forth in its conditional license, will receive a provisional tariff approval valid for 90 days which ensures the developer s place under the cap. During this 90-day period, the developer is supposed to close the financing terms. Once the financing terms are finalized, the provisional tariff approval will become permanent, and the tariff will be secured for 20 years from commencement of commercial operation. The developer may commence the construction and installation of the power plant upon receipt of the permanent tariff approval. For lands owned by the ILA, in addition to statutory approval, the developer must (i) obtain the consent of the ILA to build the power plant and (ii) meet further conditions based on the land determination.

Table of Contents

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 74.1% of our total revenues for the year ended December 31, 2011 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 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 2008, we experienced protracted failures of two of the Steamboat 2 and 3 power plant s turbines, which were not manufactured by us. We replaced the turbines and successfully upgraded the power plant. 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 a number of exploration sites where we have conducted tests, acquired land rights, and drilled test wells, which would adversely affect our development of geothermal power plants. Prior to our acquisition of the Steamboat Hills power plant, one of the wells related to the power plant experienced an uncontrolled release. The high temperature and high pressure in the Puna power plant s geothermal energy resource requires special reservoir management and monitoring. 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. At Momotombo, early operations without injection resulted in reservoir pressure decline and consequent reduced productivity and scale plugging in the formation near the producer wellbores. 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 sustainable 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, or 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 become a wasting asset, 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

Table of Contents

control. It is possible that the solar energy at our Solar PV plants will be lower than expected, perhaps significantly so, 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 recently entered the solar energy sector of the renewable energy industry and have signed a PPA with IID for a 10 MW Solar PV project to be built in Imperial Valley, California and we entered into a joint venture with third parties to develop Solar PV power projects in Israel. 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 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 development or construction in the United States, Kenya, Chile, Guatemala, New Zealand 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 which 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.

Table of Contents

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 and intermediaries in the United States and elsewhere around the world, concerns over 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 with existing lenders, waivers or modifications of the terms of existing financing arrangements 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 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, 2011, we had approximately $1,025.0 million of total consolidated indebtedness, of which approximately $476.8 million represented non-recourse debt 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 previous 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.

Table of Contents

Our foreign power plants 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 risks may delay or reduce our ability to profit from such power plants.

We have substantial operations outside of the United States that generated revenues in the amount of $187.3 million for the year ended December 31, 2011, which represented 42.9% of our total revenues for such twelve-month period. 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 for the same type of legal certainty and rights, in connection with our contractual relationships in such countries, as are afforded to our power plants 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. 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 market;
- breach or repudiation of important contractual undertakings by governmental entities; and
- expropriation and confiscation of assets and facilities.

In particular, 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 Nicaragua, subsidiaries of Union Fenosa, which are the off-takers of our Momotombo power plant, have been experiencing difficulties adjusting the tariffs charged to their customers, thus affecting their ability to pay for electricity they purchase from power generators. This may adversely affect our Momotombo power plant. In addition, recent sentiment in the country suggests increased opposition to the presence of foreign investors generally, including in the electricity sector. In Kenya, the government is continuing to make an effort to deliver on campaign promises to reduce the price of electricity and is applying pressure on IPPs to lower their tariffs. In addition, further re-organization of KPLC has been made with the formation of a new company known as KETRACO to undertake power transmission. KPLC will continue to undertake power distribution. This re-organization is in accordance with the National Energy Policy (Sessional Paper No. 4 of 2004). No announcement has been made as to whether KPLC s transmission assets will be transferred to KETRACO. In addition, the state owned GDC has been formed and is operational. GDC is charged with the responsibility of geothermal assessment, drilling of steam wells and sale of steam to future IPPs and to KenGen for electricity generation. 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.

Table of Contents

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 27.7%, 13.0%, 10.6%, and 8.0%, respectively, of our revenues for the year ended December 31, 2011. Neither we nor any of our affiliates makes any representations as to the financial condition or creditworthiness of any purchaser under a PPA, and nothing in this annual report should be construed as such a representation.

There is a risk that any one or more of the power purchasers may not fulfill their respective payment obligations under their PPAs. For example, as a result of the energy crisis in California in the early 2000s, Southern California Edison withheld payments it owed under various of its PPAs with a number of power generators (such as the Ormesa, Heber, and Mammoth power plants) payable for certain energy delivered between November 2000 and March 2001 under such PPAs until March 2002. 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 short run avoided costs in effect 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 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, Desert Peak 2, Galena 2, Galena 3, Jersey Valley, McGinness Hills, Tuscarora and North Brawley 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

Table of Contents

is forced to obtain from an alternate source. Five of these nine plants were in commercial operation in 2011, and to date the shortfall amount has not been material. In addition, we may be required to make payments to the relevant power purchaser in an amount equal to its replacement costs relating to any renewable energy credits we do not provide as required under the relevant PPA. We may be subject to certain penalties, and we may also be required to pay liquidated damages if certain minimum performance requirements are not met under certain of our PPAs. With respect to the Brady PPA, we may also be required to pay liquidated damages of approximately $1.5 million (increased by the percent change in GNP deflator) to our power purchaser if the relevant power plant does not maintain availability of at least 85% during applicable peak periods. Any or all of these could materially and adversely affect our business, financial condition, future results and cash flow.

The short run avoided costs 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 for energy 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 has been fixed through April 2012 and thereafter will be based on Southern California Edison s short run avoided costs, as determined by the CPUC. These short run avoided costs 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 short run avoided cost 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) will have 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 will allow a Qualifying Facility to choose a pricing methodology option going forward from the pricing effective date , which in Ormat s case will be the end of the fixed rate period that terminates 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 include:

(1) switching to a new SRAC methodology, which has fixed, 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;

(2) the same formula specified in (1) above but with somewhat higher heat rates, no GHG cost adder and no location adjustment (for renewable resources);

(3) the same formula specified in (1) above but with heat rates between options (1) and (2) and a fixed GHG payment of $20 per metric ton for allowances used by a facility until December 31, 2014;

(4) the same pricing terms as (3) above, but tied to actual GHG costs imposed on a facility, capped at $12.50 per metric ton until December 31, 2014; or

(5) a 90-day negotiation period to see if the parties can turn the PPA into a tolling agreement on agreed terms. This 90-day period has since expired.

Table of Contents

If an existing Qualifying Facility chooses not to enter into a Legacy PPA Amendment, its pricing under the existing Legacy PPA will revert at the end of the current fixed rate period (meaning, in Ormat s case, the one that ends April 2012) to the SRAC formula pricing specified in (1) above.

The Global Settlement further provides that after July 1, 2015 if the term of a Qualifying Facility s Legacy PPA expires, the utility will have no obligation to purchase power from the Qualifying Facility if the Qualifying Facility has a generating capacity in excess of 20 MW. Until July 1, 2015, a transition PPA will be available for Qualifying Facilities with Legacy PPAs that expire, which will incorporate the pricing structure outlined above. The investor-owned utilities have also agreed to conduct competitive solicitations for CHP Qualifying Facilities output (similar to the competitive solicitations available to renewable generators under the State s Renewables Portfolio Standard program, but with various differences). There are also several other contracting options under the Global Settlement, including bilateral contracts with the investor-owned utilities. 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. Our power purchasers or we 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, which currently are significant, may increase in the future and could materially and adversely affect our business, financial condition, future results and cash flow; any non-compliance with such laws or regulations may result in the imposition of liabilities which could materially and adversely affect our business, financial condition, future results and cash flow.

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. 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. In addition, 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. As of the date of this report, we have not yet obtained certain permits and government approvals required for the completion and successful operation of power plants under construction or enhancement. In addition, a nearby municipality has informed our Amatitlan power plant that an additional building permit should be obtained from such municipality before construction commences. 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. 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.

Table of Contents

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 isobutane, isopentane, 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, the same 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

Table of Contents

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 related to solar power could cause the revenues we expect to derive from our solar power joint venture to decline.

Today, the cost of solar power exceeds the cost of power furnished by the electric utility grid in most locations. As a result, federal, state and local government bodies in many countries have provided various incentives in the form of rebates, tax credits, mandated feed-in-tariffs and other incentives to end users, distributors, system integrators and manufacturers of solar power products to promote the use of solar energy to reduce dependency on other forms of energy. These government economic incentives could be reduced or eliminated. Reductions in, or eliminations or expirations of, incentives related to solar power could result in decreased demand for solar power and adversely affect the revenues we expect to derive from our solar power joint venture in Israel. In the United States, a federal tax credit for solar power projects is currently scheduled to expire at the end of 2016. In addition, it is possible that the federal government could impose new tariffs on solar panels imported from China, as part of a trade complaint currently pending with the U.S. Department of Commerce and the International Trade Commission.

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. We do not represent a significant competitive presence in the solar power market. 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 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, our subsidiary that owns that power plant would be excused from its obligations under the relevant PPA. However, 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. Accordingly, our business, financial condition, future results and cash flows could be materially and adversely affected.

Table of Contents

The existence of a force majeure event or a forced outage affecting 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.

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, 2011, from the power plants utilizing the IID transmission system, were approximately $102.2 million. The impact of such force majeure would depend on the duration thereof, with longer outages resulting in greater revenue loss.

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 may 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.

Table of Contents

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 transportation 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 the extension of an interstate highway (to be named U.S. 580) by the Nevada Department of Transportation, 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.

Our success is largely dependent on the skills, experience and efforts of our senior management team and other key personnel. In particular, our success depends on the continued efforts of Lucien Bronicki, Dita Bronicki and Yoram Bronicki, and other key employees. The loss of the services of any key employee could materially harm our business, financial condition, future results and cash flow. Although to date we have been successful in retaining the services of senior management and have entered into employment agreements with Lucien Bronicki, Dita Bronicki and Yoram Bronicki, such members of our senior management may terminate their employment agreements without cause and with notice periods ranging from 30 to 180 days. In addition, while Lucien and Dita Bronicki have not indicated any plan to retire, they are 77 and 70 years old, respectively, and either of them may decide to retire at any time. We may also not be able to locate or employ on acceptable terms qualified replacements for our senior management or key employees if their services were no longer available.

Table of Contents

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. 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. 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. 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.

Table of Contents

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.

Table of Contents

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.

Operations in Israel accounted for approximately 22.9%, 18.8%, and 29.7% of our operating expenses in the years ended December 31, 2011, 2010, and 2009, respectively. 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. At the end of December 2008, Israel engaged in an armed conflict with Hamas lasting for over three weeks, 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 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 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

Table of Contents

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, any sublease for a period of more than five years may require the prior approval of the Israel Land Administration. As a result, the initial term of our sublease with Ormat Industries is for a period of four years and eleven months beginning on July 1, 2004, extendable to twenty-five years less one day (which includes the initial term). 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.

Some 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.

Three of our seven directors are directors and/or officers of Ormat Industries, namely Lucien Bronicki, Dita Bronicki and Yoram Bronicki. In addition, four of our executive officers are also executive officers of Ormat Industries. Specifically, our Chief Executive Officer and Director, Dita Bronicki, is the Chief Executive Officer of our parent; our Chief Financial Officer, Joseph Tenne, 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.

Table of Contents

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

Ormat Industries Ltd. holds approximately 60% of our common stock. Bronicki Investments Ltd. holds approximately 35.1% of the outstanding shares of common stock of Ormat Industries Ltd. as of February 24, 2012 (35.1% on a fully diluted basis). Bronicki Investments Ltd. is a privately held Israeli company and is controlled by Lucien and Dita Bronicki. Because of these holdings, our parent company will be able to exercise control over all matters requiring stockholder approval, including the election of directors, amendment of our certificate of incorporation and approval of significant corporate transactions, and they will have significant control over our management and policies. The directors elected by these stockholders will be able to significantly influence decisions affecting our capital structure. 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. For example, our controlling stockholders will be able to control the sale or other disposition of our product business to another entity or the transfer of such business outside of the State of Israel; as such action requires the affirmative vote of at least 75% of our outstanding shares.

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 Ltd., 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.

The SOX Act imposes significant regulatory, corporate and operational requirements on the Company. Failure to comply with such provisions may have significant adverse consequences to the Company.

As a public company, we are subject to the SOX Act. The SOX Act contains a variety of provisions affecting public companies, including but not limited to, corporate governance requirements, our relationship with our auditors, evaluation of our internal disclosure controls and procedures, and evaluation of our internal control over financial reporting. See Management s Report on Internal Control over Financial Reporting and Item 9A. Controls and Procedures.

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.

Table of Contents

ITEM 3. ***LEGAL PROCEEDINGS***

There were no material developments in any legal proceedings to which the Company is a party during the fiscal year 2011, other than as described below.

Securities Class Actions

Following the Company s public announcement that it would restate certain of its financial results due to a change in the Company s accounting treatment for certain exploration and development costs, three securities class action lawsuits were filed in the United States District Court for the District of Nevada on March 9, 2010, March 18, 2010 and April 7, 2010. These complaints assert claims against the Company and certain officers and directors for alleged violation of Sections 10(b) and 20(a) of the Exchange Act. One complaint also asserts claims for alleged violations of Sections 11, 12(a)(2) and 15 of the Securities Act. All three complaints allege claims on behalf of a putative class of purchasers of Company common stock between May 6, 2008 or May 7, 2008 and February 23, 2010 or February 24, 2010. These three lawsuits were consolidated by the Court in an order issued on June 3, 2010 and the Court appointed three of the Company s stockholders to serve as lead plaintiffs.

Lead plaintiffs filed a consolidated amended class action complaint (CAC) on July 9, 2010 that asserts claims under Sections 10(b) and 20(a) of the Exchange Act on behalf of a putative class of purchasers of Company common stock between May 7, 2008 and February 24, 2010. The CAC alleges that certain of the Company s public statements were false and misleading for failing to account properly for the Company s exploration and development costs based on the Company s announcement on February 24, 2010 that it was going to restate certain of its financial results to change its method of accounting for exploration and development costs in certain respects. The CAC also alleges that certain of the Company s statements concerning the North Brawley project were false and misleading. The CAC seeks compensatory damages, expenses, and such further relief as the Court may deem proper.

Defendants filed a motion to dismiss the CAC on August 13, 2010. On March 3, 2011, the court granted in part and denied in part defendants motion to dismiss. The court dismissed plaintiffs allegations that the Company s statements regarding the North Brawley project were false or misleading, but did not dismiss plaintiffs allegations regarding the 2008 restatement. Defendants answered the remaining allegations in the CAC regarding the restatement on April 8, 2011 and the case has now entered the discovery phase. On July 22, 2011, plaintiffs filed a motion to certify the case as a class action on behalf of a class of purchasers of Company common stock between February 25, 2009 and February 24, 2010, and defendants filed an opposition to the motion for class certification on October 4, 2011.

Subsequently, the parties participated in a mediation where they reached an agreement in principle to settle the securities class action lawsuits. Under the proposed class action settlement, the claims against the Company and its officers and directors will be dismissed with prejudice and released in exchange for a cash payment of $3.1 million to be funded by the Company s insurers. The proposed settlement remains subject to the satisfaction of various conditions, including negotiation and execution of a final stipulation of settlement, and approval by the U.S. District Court for the District of Nevada following notice to members of the class.

The Company and the individual defendants have steadfastly maintained that the claims raised in the securities class action lawsuits were without merit, and have vigorously contested those claims. As part of the settlement, the Company and the individual defendants continue to deny any liability or wrongdoing under the securities laws or otherwise.

Stockholder Derivative Cases

Four stockholder derivative lawsuits have also been filed in connection with the Company s public announcement that it would restate certain of its financial results due to a change in the Company s accounting treatment for certain exploration and development costs. Two cases were filed in the Second Judicial District

Table of Contents

Court of the State of Nevada in and for the County of Washoe on March 16, 2010 and April 21, 2010 and two cases were filed in the United States District Court for the District of Nevada on March 29, 2010 and June 7, 2010. All four lawsuits assert claims brought derivatively on behalf of the Company against certain of its officers and directors for alleged breach of fiduciary duty and other claims, including waste of corporate assets and unjust enrichment.

The two stockholder derivative cases filed in the Second Judicial District Court of the State of Nevada in and for the County of Washoe were consolidated by the Court in an order dated May 27, 2010 and the plaintiffs filed a consolidated derivative complaint on September 7, 2010. In accordance with a stipulation between the parties, defendants filed a motion to dismiss on November 16, 2010. On April 18, 2011, the court stayed the state derivative case pending the resolution of the securities class action. The Company cannot make an estimate of the reasonably possible loss or range of reasonably possible loss on the state derivative cases.

The two stockholder derivative cases filed in the United States District Court for the District of Nevada were consolidated by the Court in an order dated August 31, 2010, and plaintiffs filed a consolidated derivative complaint on October 28, 2010. The Company filed a motion to dismiss on December 13, 2010. On March 7, 2011, the Court transferred the federal derivative case to the Court presiding over the securities class action, and on August 29, 2011, the Court stayed the federal derivative case pending the resolution of the securities class action. The Company cannot make an estimate of the reasonably possible loss or range of reasonably possible loss on the state derivative cases.

The Company believes the allegations in these purported derivative actions are without merit and is defending the actions vigorously.

Other

On May 19, 2011, FERC issued an order which denied the Company s exemptions for requirements relating to Sections 205 and 206 of the Federal Power Act and directed certain of the Company s REG facilities to make refunds to their customers, equaling the time value of the revenues collected during the periods of non-compliance with the qualifying facilities , in an amount of approximately $1.6 million. On June 17, 2011, the Company requested a rehearing to obtain relief on this mandated refund payment. On July 18, 2011, FERC issued an Order Granting Rehearing for Further Consideration in order to afford additional time for consideration of the matters raised. In February 2012, FERC reached its ruling that a settlement amount was due from the Company which had an immaterial impact to the December 31, 2011 financial statements.

On January 4, 2012, the California Unions for Reliable Energy (CURE) filed a petition in Alameda Superior Court, naming the California Energy Commission (CEC) and the Company as defendant and real party in interest, respectively. The petition asks the court to order the CEC to vacate its decision which denied, with prejudice, the complaint filed by CURE against the Company with the CEC. The CURE complaint alleged that the Company s North Brawley Project and East Brawley Project both exceed the CEC s 50 MW jurisdictional threshold and therefore are subject to CEC licensing authority rather than Imperial County. In addition, the CURE petition asks the court to investigate and halt any ongoing violation of the Warren Alquist Act by the Company, and to award CURE attorney s fees and costs. As to North Brawley, CURE alleges that the CEC decision violated the Warren Alquist Act because it failed to consider provisions of the County permit for North Brawley, which CURE contends authorizes the Company to build a generating facility with a number of Ormat Energy Converters capable of generating more than 50 MW. As to East Brawley, CURE alleges that the CEC decision violated the Warren Alquist Act because it failed to consider the conditional use permit application for East Brawley, which CURE contends shows that the Company requested authorization to build a facility with a number of Ormat Energy Converters capable of generating more than 50 MW.

The Company believes that the petition is without merit and intends to respond and take necessary legal action to dismiss the proceedings. The Company has thirty days in which to respond to CURE s petition. Filing of the petition in and of itself does not have any immediate adverse implications for the North Brawley or East Brawley projects and the Company continues to operate the North Brawley project in the ordinary course and continues with its development work on the East Brawley project.

In addition, from time to time, the Company is named as a party to various 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 financial statements as a whole.

ITEM 4. ***MINE SAFETY DISCLOSURES***

Not applicable.

Table of Contents

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 24, 2012, there were 17 record holders of the Company s common stock. On February 24, 2012, our stock s closing price as reported on the NYSE was $19.97 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 11 to our consolidated financial statements set forth in Part II, 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
February 23, 2010	$ 0.12	March 16, 2010	March 25, 2010
May 5, 2010	$ 0.05	May 18, 2010	May 25, 2010
August 4, 2010	$ 0.05	August 17, 2010	August 26, 2010
November 2, 2010	$ 0.05	November 17, 2010	November 30, 2010
February 22, 2011	$ 0.05	March 15, 2011	March 24, 2011
May 4, 2011	$ 0.04	May 18, 2011	May 25, 2011
August 3, 2011	$ 0.04	August 16, 2011	August 25, 2011

High/Low Stock Prices:

Ormat Technologies, Inc. (ORA) High and Low Prices for the years ended December 31, 2010 and 2011, and from January 1, 2012 until February 24, 2012:

	First Quarter 2010	Second Quarter 2010	Third Quarter 2010	Fourth Quarter 2010	First Quarter 2011	Second Quarter 2011	Third Quarter 2011	Fourth Quarter 2011	January 1 to February 24, 2012
High	$ 38.00	$ 32.35	$ 29.45	$ 30.08	$ 31.18	$ 26.13	$ 22.90	$ 19.69	$ 19.97
Low	$ 27.68	$ 26.55	$ 26.13	$ 26.80	$ 23.24	$ 20.60	$ 14.43	$ 15.44	$ 16.25

Table of Contents

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, 2011 for our common stock, compared to the Standard and Poor s Composite 500 Index, and two peer groups.

	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
Ormat Technologies Inc	$ 100	$ 109	$ 174	$ 245	$ 367	$ 212	$ 252	$ 197	$ 120
Standard & Poor s Composite									
500 Index	$ 100	$ 108	$ 111	$ 126	$ 131	$ 80	$ 99	$ 112	$ 112
IPP Peers*	$ 100	$ 119	$ 110	$ 167	$ 163	$ 131	$ 187	$ 218	$ 228
Renewable Peers*	$ 100	$ 108	$ 171	$ 169	$ 299	$ 108	$ 114	$ 77	$ 28

* IPP Peers are The AES Corporation, NRG Energy Inc., Calpine Corporation and International Power PLC. Renewable Energy (Renewable) Peers are Acciona S.A., Evergreen Solar Inc., Energy Conversion Devices Inc., NGP., 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.

98

Table of Contents

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, 2011, 2010 and 2009 and as of December 31, 2011 and 2010 from our audited consolidated financial statements set forth in Part II, Item 8 of this annual report. We have derived the selected consolidated financial data for the years ended December 31, 2008 and 2007 and as of December 31, 2009, 2008 and 2007 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 set forth in Part II, Item 8 of this annual report.

	Year Ended December 31,				
	2011	2010	2009	2008	2007
	(In thousands, except per share data)				
Statements of Operations Data:					
Revenues:					
Electricity	$ 323,849	$ 291,820	$ 252,621	$ 251,373	$ 215,969
Product	113,160	81,410	159,389	92,577	79,950
Total revenues	437,009	373,230	412,010	343,950	295,919
Cost of revenues:					
Electricity	244,037	242,326	179,101	169,297	148,698
Product	76,072	53,277	112,450	72,755	68,036
Total Cost of revenues	320,109	295,603	291,551	242,052	216,734
Gross margin	116,900	77,627	120,459	101,898	79,185
Operating expenses:					
Research and development expenses	8,801	10,120	10,502	4,595	3,663
Selling and marketing expenses	16,207	13,447	14,584	10,885	10,645
General and administrative expenses	27,885	27,442	26,412	25,938	21,416
Write-off of unsuccessful exploration activities		3,050	2,367	9,828	
Operating income	64,007	23,568	66,594	50,652	43,461
Other income (expense):					
Interest income	1,427	343	639	3,118	6,565
Interest expense, net	(69,459)	(40,473)	(16,241)	(14,945)	(29,745)
Foreign currency translation and transaction gains (losses)	(1,350)	1,557	(1,695)	(4,421)	(1,339)
Income attributable to sale of tax benefits	11,474	8,729	15,515	18,118	6,488
Gain on acquisition of controlling interest		36,928			
Gain from extinguishment of liability			13,348		
Other non-operating income (expense), net	671	130	200	(3,424)	(1,130)
Income from continuing operations, before income taxes and equity in income (losses) of investees	6,770	30,782	78,360	49,098	24,300
Income tax benefit (provision)	(48,535)	1,098	(15,430)	(5,310)	(1,822)
Equity in income (losses) of investees, net	(959)	998	2,136	1,725	4,742
Income (loss) from continuing operations	(42,724)	32,878	65,066	45,513	27,220
Discontinued operations:					
Income (loss) from discontinued operations, net of related tax		14	3,487	(2,221)	
Gain on sale of a subsidiary in New Zealand, net of related tax		4,336			
Net income (loss)	(42,724)	37,228	68,553	43,292	27,220

Net loss (income) attributable to noncontrolling interest	(332)	90	298	316	156
Net income (loss) attributable to the Company s stockholders	$ (43,056)	$ 37,318	$ 68,851	$ 43,608	$ 27,376

Table of Contents

	Year Ended December 31, 2011	2010	2009	2008	2007
	(In thousands, except per share data)				
Earnings per share attributable to the Company s stockholders:					
Basic:					
Income (loss) from continuing operations	$ (0.95)	$ 0.72	$ 1.44	$ 1.04	$ 0.71
Discontinued operations		0.10	0.08	(0.05)	
Net income (loss)	$ (0.95)	$ 0.82	$ 1.52	$ 0.99	$ 0.71
Diluted:					
Income (loss) from continuing operations	$ (0.95)	$ 0.72	$ 1.43	$ 1.03	$ 0.70
Discontinued operations		0.10	0.08	(0.05)	
Net income (loss)	$ (0.95)	$ 0.82	$ 1.51	$ 0.98	$ 0.70
Weighted average number of shares used in computation of earnings per share attributable to the Company s stockholders:					
Basic	45,431	45,431	45,391	44,182	38,762
Diluted	45,431	45,452	45,533	44,298	38,880
Cash dividend per share declared during the year	$ 0.13	$ 0.27	$ 0.25	$ 0.20	$ 0.22
Balance Sheet Data (at end of year):					
Cash and cash equivalents	$ 99,886	$ 82,815	$ 46,307	$ 34,393	$ 47,227
Working capital	98,415	66,932	55,652	3,296	22,337
Property, plant and equipment, net (including construction-in process)	1,889,083	1,696,101	1,517,288	1,334,859	977,400
Total assets	2,314,718	2,043,328	1,864,193	1,630,976	1,277,368
Long-term debt (including current portion)	1,025,010	789,669	624,442	386,635	322,472
Notes payable to Parent (including current portion)			9,600	26,200	57,847
Equity	906,644	945,227	911,695	847,235	627,836

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 primarily engaged 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, which we refer to as our

Electricity Segment and Product Segment. In our Electricity 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

Table of Contents

power plants that produce electricity generated by Solar PV systems that we do not manufacture. In our Product 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, Kenya, and Nicaragua, as well as REG plants in the United States. During the years ended December 31, 2011 and 2010, our consolidated power plants generated 3,918,156 MWh and 3,762,283 MWh, respectively.

For the year ended December 31, 2011, our Electricity Segment represented approximately 74.1% of our total revenues, while our Product Segment represented approximately 25.9% of our total revenues. For the year ended December 31, 2010, our Electricity Segment represented approximately 78.2% of our total revenues, while our Product Segment represented approximately 21.8% of our total revenues.

For the year ended December 31, 2011, our total revenues increased by 17.1% (from $373.2 million to $437.0 million) over the previous year.

For the year ended December 31, 2011, Electricity Segment revenues were $323.8 million, compared to $291.8 million for the year ended December 31, 2010, an increase of 11.0%, while Product Segment revenues for the year ended December 31, 2011 were $113.2 million, compared to $81.4 million during the year ended December 31, 2010, an increase of 39.0%.

Revenues from our Electricity Segment are relatively predictable, as they are derived from sales of electricity generated by our power plants pursuant to long-term PPAs. However, our variable price PPAs in California are subject to the impact of fluctuations in natural gas prices. The price for electricity under all but one of our PPAs is effectively a fixed price until May 1, 2012. The exception is the 25 MW PPA of the Puna complex. It has a monthly variable energy rate based on the local utility s avoided costs, which is the incremental cost that the power purchaser avoids by not having to generate such electrical energy itself or purchase it from others. Beginning May 2012, the PPAs for the Ormesa complex, Mammoth complex, Heber 1 and Heber 2 power plants, will convert from fixed to variable energy price PPAs based on SCE s SRAC. In the year ended December 31, 2011, approximately 82.4% of our electricity revenues were derived from contracts with fixed energy rates, and therefore most of our electricity revenues were not affected by the fluctuations in energy commodity prices. However, electricity revenues are subject to seasonal variations and can be affected by higher-than-average ambient temperatures, as described below under the heading Seasonality.

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, relevant technical and geological matters and other relevant 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, 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

Table of Contents

geothermal resources in the United States as costs for electricity generated from geothermal resources have become more competitive relative to fossil fuel generation. This has partly been due to increasing natural gas and oil prices during much of this period and, equally important, to newly enacted 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 production or investment tax credits as well as cash grants (which are discussed in more detail in the section entitled Government Grants and Tax Benefits). In response, the geothermal industry in the U.S. has seen a wave of new entrants and, over the last several years, consolidation involving smaller developers. We see the increasing demand for energy generated from geothermal and other renewable resources in the United States and the further introduction of renewable portfolio standards as significant trends affecting our industry today and in the immediate future. Our operations and the trends that from time to time impact our operations are subject to market cycles.

We expect to continue to generate the majority of our revenues from our Electricity Segment through the sale of electricity from our power plants. Substantially all of our current revenues from the sale of electricity are derived from fully-contracted payments under long-term PPAs. We also intend to continue to pursue growth in our recovered energy business and in the Solar PV sector.

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 affected by the following trends, factors and uncertainties:

Our primary focus continues to be our organic growth through exploration, development, construction of new projects and enhancements of existing power plants. We expect that this 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.

We expect that 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. Several states and regions are already addressing climate change. 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. In 2008, the CARB approved a Scoping Plan to carry out regulations implementing AB 32. In December 2010, CARB approved cap-and-trade regulations to reduce California s GHG emissions under AB 32. The cap-and-trade regulation, the first phase of which is contemplated to be initiated in January of 2012 with compliance obligations commencing in January 2013, will set a statewide limit on emissions from sources responsible for emitting 80% of California s GHGs, and, according to CARB, will help establish a price signal needed to drive long-term investment in cleaner fuels and more efficient use of energy. However, implementation of this cap-and-trade program under AB 32 has been the subject of legal challenges that may hinder and/or ultimately thwart its implementation. In September of 2006, California also passed Senate Bill 1368, which prohibits the state s utilities from entering into long-term financial commitments for base-load generation with power plants that fail to meet a CO_2 emission performance standard established by the California Energy Commission and the California Public Utilities Commission. California s long-term climate change goals are reflected in Executive Order S-3-05, which requires a reduction in GHGs to: (i) 2000 levels by 2010; (ii) 1990 levels by 2020; and (iii) 80% of 1990 levels by 2050. In addition to California, twenty-two other states have set GHG emissions targets or goals (Arizona, Colorado, Connecticut, Florida, Hawaii, Illinois, Maine, Maryland, Massachusetts, Michigan, Minnesota, Montana, New Hampshire, New Jersey, New Mexico, New York, Oregon, Rhode Island, Utah, Vermont, Virginia and Washington). Regional initiatives, such as the Western Climate Initiative (which includes seven U.S. states 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 September 2008, the first-in-the-nation auction of CO_2 allowances was held under the RGGI, a regional cap-and-trade system, which includes nine Northeast and Mid-Atlantic States. Under RGGI, the participating states plan to stabilize power section carbon emissions at their capped level, and then reduce the cap by a total of 10% at a rate of 2.5% each year between 2015 and 2018. In addition, twenty-nine states and the District of Columbia have adopted RPS and eight other states have adopted renewable portfolio goals. On April 12, 2011, Governor Jerry Brown signed California Senate Bill X1-2 (SBX1-2) which increased California s RPS to 33% by December 31, 2020 and instituted a tradable REC program, according to which California utilities can purchase three products to comply with SBX1-2: (i) bundled electricity and RECs from electricity generators that interconnect with a California balancing authority, (ii) tradable RECs that are purchased either from out-of-state electricity generators or in-state electricity generators that do not interconnect with a California balancing authority, and (iii) firmed and shaped transactions with out-of-state electricity generators. Until December 31, 2013 unbundled tradable RECs may account for only 25% of a utility s annual RPS, but this limit on unbundled RECs does not apply to municipal utilities and other small entities. The percentage will be reduced after 2013. 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. 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 economic conditions. We see this increased demand and in particular the impact of the increase in California RPS, as one of the most significant opportunities for us to expand existing power plants and develop new power plants.

Outside of the United States, 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.

We expect competition from the wind and solar power generation industry to continue. While the expected demand for renewable energy is large enough, the increase in competition 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 baseload electricity, such as geothermal-based energy, will continue to be a leading source of renewable energy in areas with commercially viable geothermal resource.

We expect increased competition from binary power plant equipment suppliers. While we believe that we have a distinct competitive advantage based on our accumulated experience and current worldwide share of installed binary generation capacity, which is in excess of 90%, an increase in competition may impact our ability to secure new purchase orders from potential customers. The increased competition also may lead to a reduction in prices that we are able to charge for our binary equipment, which in turn may impact our profitability.

North America is the largest and most developed natural gas market in the world. As recently as five years ago, the region was considered to be short on supply, with an expected need to import significant volumes of liquefied natural gas (LNG) from the international gas market to balance supply with expected demand. The rise of shale gas production over the last three years has completely changed the natural gas market landscape in North America. The unexpected growth in supply at increasingly lower costs has come at a time when the U.S. economy has been facing constrained demand growth for natural gas. Among other things, this has led to an increased interest in exporting natural gas from the U.S., in the form of LNG. Various natural gas companies and other project sponsors have recently applied, and in some cases, have already received an export license to export liquefied natural gas, to countries with which the U.S. has a free trade agreement providing comity in trading natural gas (FTA-nations) and to other non-FTA nations. At the same time, environmentalists, regulators, natural gas companies and the public have been focusing more attention on the potential environmental impacts associated with natural gas fracking, including possible chemicals leakage, ground water contamination and other effects, which may slow development in some areas. The changing natural gas landscape, and 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, all combine to affect the pricing under our PPAs that have SRAC pricing or that are otherwise tied to natural gas prices.

Our PPA for 25 MW in the Puna complex has a monthly variable energy rate based on the local utility s short run avoided costs, which is the incremental cost that the power purchaser avoids by not having to generate such electrical energy itself or purchase it from others. 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 resulting in a reduction of the energy rate that we may charge under this PPA and under any other variable energy rate in PPAs that we may enter into in the future.

Our PPAs for the Ormesa complex, Mammoth complex and Heber 1 and 2 power plants are fixed until May 1, 2012. Thereafter, the energy price component under these PPAs will change from fixed rate to variable rate based on SRAC pricing, as required under a global settlement relating primarily to purchase and payment obligations of investor-owned utilities in California. These PPAs may be impacted by fluctuations in natural gas prices.

We are experiencing a notable decrease in competition in the geothermal industry, specifically in the acquisition of geothermal leases. The reduced level of competition has contributed to a decrease in lease costs.

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 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 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. Those risks include the partial privatization of the electricity sector in Guatemala, labor unrest in Nicaragua 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 foreign power plants to mitigate these risks, insurance does not provide complete coverage with respect to all such risks.

The Energy Policy Act of 2005 authorizes FERC to revise PURPA so as to terminate the obligation 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 except one of our current contracts are long-term. The FERC recently 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.

Table of Contents

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 relatively predictable as they are derived from the sale of electricity from our power plants pursuant to long-term PPAs. However, we have variable price PPAs in California and Hawaii. Our California PPAs are subject to the impact of fluctuations in natural gas prices. The prices paid for electricity pursuant to the PPA of the Puna complex for 25 MW in Hawaii are impacted by the price of oil. Accordingly, our revenues from those power plants may fluctuate. Our Electricity Segment revenues are also subject to seasonal variations, as more fully described in the section entitled Seasonality , and may also be affected by higher-than-average ambient temperature, which could cause a decrease in the generating capacity of our power plants, and by unplanned major maintenance activities related to our power plants.

Our PPAs generally provide for the payment of 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 short run avoided costs (the incremental costs that the power purchaser avoids by not having to generate such electrical energy itself or purchase it from others). 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 are generally less predictable than revenues from our Electricity Segment. This is because larger customer orders for our products are typically a 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 often subject to various contingencies such as the customer s ability to raise the necessary financing for a project. As a result, 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, our revenues from our Product Segment fluctuate (at times, extensively) from period to period. In 2011, we experienced a significant increase in our Product Segment customer orders, which has increased our Product Segment backlog. We expect that our Product Segment revenues will increase over the next two years as a result of these new orders and increased backlog, which is described in Item 1 Business.

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

	Revenues in Thousands Year Ended December 31,			% of Revenues for Period Indicated Year Ended December 31,		
	2011	2010	2009	2011	2010	2009
Revenues:						
Electricity	$ 323,849	$ 291,820	$ 252,621	74.1%	78.2%	61.3%
Product	113,160	81,410	159,389	25.9	21.8	38.7
Total	$ 437,009	$ 373,230	$ 412,010	100.0%	100.0%	100.0%

Table of Contents

Geographical Breakdown of Revenues

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

	Revenues in Thousands Year Ended December 31,			% of Revenues for Period Indicated Year Ended December 31,		
	2011	2010	2009	2011	2010	2009
Electricity Segment:						
United States	$ 249,740	$ 220,107	$ 182,219	77.1%	75.4%	72.1%
Foreign	74,109	71,713	70,402	22.9	24.6	27.9
Total	$ 323,849	$ 291,820	$ 252,621	100.0%	100.0%	100.0%
Product Segment:						
United States	$	$ 10,177	$ 63,735	0.0%	12.5%	40.0%
Foreign	113,160	71,233	95,654	100.0	87.5	60.0
Total	$ 113,160	$ 81,410	$ 159,389	100.0%	100.0%	100.0%

Seasonality

The prices paid for the electricity generated by our domestic power plants pursuant to our PPAs are subject to seasonal variations. The prices paid for electricity under the PPAs with Southern California Edison for the Heber 1 and 2 plants, the Mammoth complex, the Ormesa complex, and the North Brawley plant are higher in the months of June through September. As a result, we receive, and will receive in the future, higher revenues during such months. The prices paid for electricity pursuant to the PPAs of our power plants in Nevada have no significant changes during the year. In the winter, due principally to the lower ambient temperature, our power plants produce more energy and as a result we receive higher energy revenues. However, the higher capacity payments payable by Southern California Edison in California 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 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 include operation and maintenance expenses, such as depreciation and amortization, 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, and insurance. In our California power plants our principal cost of revenues also includes transmission charges, scheduling charges and purchases of make-up water for use in our cooling towers. 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 3.7% of Electricity Segment revenues for each of the years ended December 31, 2011 and December 31, 2010.

Product Segment

The principal cost of revenues attributable to our Product Segment include materials, salaries and related employee benefits, expenses related to subcontracting activities, and transportation expenses. Sales commissions

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

Cash and Cash Equivalents

Our cash, cash equivalents and marketable securities as of December 31, 2011 increased to $118.4 million from $82.8 million as of December 31, 2010. This increase is principally due to: (i) $107.4 million of proceeds from the issuance of Senior Unsecured Bonds in February 2011; (ii) $24.9 million of proceeds from the sale of Class B membership units of OPC to JPM Capital in February 2011; (iii) $141.1 million of net proceeds from the sale of Series A Senior Secured Notes in October 2011 by OFC 2 to finance a portion of the construction costs of Phase I of the McGinness Hills and Tuscarora facilities; (iv) $132.7 million derived from operating activities during the year ended December 31, 2011; and (v) net proceeds of $24.6 million drawn under our revolving credit lines with commercial banks. The increase in our cash resources was partially offset by: (i) our use of $269.7 million to fund capital expenditures; (ii) repayment of $50.1 million of long-term debt; (iii) a net change in restricted cash, cash equivalents and marketable securities of $50.6 million; and (iv) cash paid to non-controlling interest of $14.0 million. Our corporate borrowing capacity under committed lines of credit with different commercial banks as of December 31, 2011 was $419.0 million, as described below in Liquidity and Capital Resources , of which we have utilized $333.9 million (including $128.9 million of letters of credit) as of December 31, 2011.

Critical Accounting Estimates and Assumptions

Our significant accounting policies are more fully described in Note 1 to our consolidated financial statements set forth in Part II, Item 8 of this annual report. However, certain of our accounting policies are particularly important to the portrayal 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. The percentage of completion method 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 no less than annually for all others, or when

Table of Contents

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 one to two 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. The up-front non-refundable bonus payments 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 would have to write-off costs associated with the project that were previously capitalized. During the years ended December 31, 2010 and 2009, we determined that the geothermal resource at four of our exploration projects would not support commercial operations and as such, we abandoned those sites. As a result of this determination, we expensed $3,050,000 and $2,367,000 of capitalized costs during the years ended December 31, 2010 and 2009, 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 $78,653,000 and $54,697,000 at December 31, 2011 and 2010, respectively. Of this amount, $36,832,000 and $33,600,000 relates to up-front bonus payments at December 31, 2011 and 2010, 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, construction-in-process, PPAs, and unconsolidated

Table of Contents

investments 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 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. 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 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. We believe that no impairment exists for 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 power plant, which is under development, was tested for impairment in the current year due to the low output and higher than expected operating costs. Based on these indicators, we tested North Brawley for recoverability by estimating its future cash flows taking into consideration the various outcomes from different generating capacities, different outcome of future rates based under its current PPA versus a new PPA that is expected to be signed 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 to complete development of the plant and projected operating expenses over the life of the plant. We applied a probability-weighted approach and considered alternative courses of action.

Using a probability-weighted approach, the estimated undiscounted cash flows exceed the carrying value of the plant ($259 million as of December 31, 2011) by approximately $103 million and therefore, no impairment occurred. Estimated undiscounted cash flows are subject to significant uncertainties. If actual cash flows differ from our current estimates due to factors that include, among others, if the plant s future generating capacity is less than approximately 37 MW, or if the capital expenditures required to complete development of the plant and/or future operating costs exceed the level of our current projections, a material impairment write-down may be required in the future.

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. Our liabilities related to the retirement of our assets 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 will either settle the obligation for its recorded amount or will 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 provided a full valuation allowance related to our U.S. deferred tax assets. In the future, if sufficient evidence of our ability to generate sufficient future taxable income in the U.S. becomes apparent, 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, we have recorded the largest amount of tax benefit with a greater than 50% likelihood of being realized upon ultimate settlement with a taxing authority that has full knowledge of all relevant information. For those income tax positions where it is not more likely than not that a tax benefit will be sustained, no tax benefit has been recognized 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 Part II, Item 8 of this annual report for information regarding new accounting pronouncements.

Table of Contents

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 the following: (i) our recent construction of new power plants and enhancement of acquired power plants; and (ii) fluctuation in revenues from our Product Segment.

	Year Ended December 31,		
	2011	2010	2009
	(In thousands, except per share data)		
Statements of Operations Historical Data:			
Revenues:			
Electricity	$ 323,849	$ 291,820	$ 252,621
Product	113,160	81,410	159,389
	437,009	373,230	412,010
Cost of revenues:			
Electricity	244,037	242,326	179,101
Product	76,072	53,277	112,450
	320,109	295,603	291,551
Gross margin			
Electricity	79,812	49,494	73,520
Product	37,088	28,133	46,939
	116,900	77,627	120,459
Operating expenses:			
Research and development expenses	8,801	10,120	10,502
Selling and marketing expenses	16,207	13,447	14,584
General and administrative expenses	27,885	27,442	26,412
Write-off of unsuccessful exploration activities		3,050	2,367
Operating income	64,007	23,568	66,594
Other income (expense):			
Interest income	1,427	343	639
Interest expense, net	(69,459)	(40,473)	(16,241)
Foreign currency translation and transaction gains (losses)	(1,350)	1,557	(1,695)
Income attributable to sale of tax benefits	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 (expense), net	671	130	200
Income from continuing operations, before income taxes and equity in income of investees	6,770	30,782	78,360
Income tax benefit (provision)	(48,535)	1,098	(15,430)
Equity in income (losses) of investees, net	(959)	998	2,136
Income (loss) from continuing operations	(42,724)	32,878	65,066
Discontinued operations:			
Income from discontinued operations, net of related tax		14	3,487
Gain on sale of a subsidiary in New Zealand, net of related tax		4,336	
Net income (loss)	(42,724)	37,228	68,553
Net loss (income) attributable to noncontrolling interest	(332)	90	298
Net income (loss) attributable to the Company s stockholders	$ (43,056)	$ 37,318	$ 68,851

Earnings (loss) per share attributable to the Company s stockholders:			
Basic:			
Income (loss) from continuing operations	$ (0.95)	$ 0.72	$ 1.44
Discontinued operations		0.10	0.08
Net Income (loss)	$ (0.95)	$ 0.82	$ 1.52
Diluted:			
Income (loss) from continuing operations	$ (0.95)	$ 0.72	$ 1.43
Discontinued operations		0.10	0.08
Net Income (loss)	$ (0.95)	$ 0.82	$ 1.51
Weighted average number of shares used in computation of earnings (loss) per share attributable to the Company s stockholders:			
Basic	45,431	45,431	45,391
Diluted	45,431	45,452	45,533

Table of Contents

	Year Ended December 31, 2011	2010	2009
Statements of Operations Percentage Data:			
Revenues:			
Electricity	74.1%	78.2%	61.3%
Product	25.9	21.8	38.7
	100.00	100.00	100.00
Cost of revenues:			
Electricity	75.4	83.0	70.9
Product	67.2	65.4	70.6
	73.2	79.2	70.8
Gross margin			
Electricity	24.6	17.0	29.1
Product	32.8	34.6	29.4
	26.8	20.8	29.2
Operating expenses:			
Research and development expenses	2.0	2.7	2.5
Selling and marketing expenses	3.7	3.6	3.5
General and administrative expenses	6.4	7.4	6.4
Write-off of unsuccessful exploration activities	0.0	0.8	0.6
Operating income	14.7	6.3	16.2
Other income (expense):			
Interest income	0.3	0.1	0.2
Interest expense, net	(15.9)	(10.8)	(3.9)
Foreign currency translation and transaction gains (losses)	(0.3)	0.4	(0.4)
Income attributable to sale of tax benefits	2.6	2.3	3.8
Gain on acquisition of controlling interest	0.0	9.9	0.0
Gain from extinguishment of liability	0.0	0.0	3.2
Other non-operating income (expense), net	0.1	0.0	0.0
Income from continuing operations, before income taxes and equity in income of investees	1.5	8.2	19.0
Income tax benefit (provision)	(11.1)	0.3	(3.7)
Equity in income (losses) of investees, net	(0.2)	0.3	0.5
Income (loss) from continuing operations	(9.8)	8.8	15.8
Discontinued operations:			
Income from discontinued operations, net of related tax	0.0	0.0	0.8
Gain on sale of a subsidiary in New Zealand, net of related tax	0.0	1.2	0.0
Net income (loss)	(9.8)	10.0	16.6
Net loss (income) attributable to noncontrolling interest	(0.1)	0.0	0.1
Net income (loss) attributable to the company s stockholders	(9.9)%	10.0%	16.7%

Comparison of the Year Ended December 31, 2011 and the Year Ended December 31, 2010

Total Revenues

Total revenues for the year ended December 31, 2011 were $437.0 million, compared to $373.2 million for the year ended December 31, 2010, which represented a 17.1% increase in total revenues. This increase is attributable to both our Electricity and Product Segments whose revenues increased by 11.0% and by 39.0%, respectively, over the same period in 2010.

Electricity Segment

Revenues attributable to our Electricity Segment for the year ended December 31, 2011 were $323.8 million, compared to $291.8 million for the year ended December 31, 2010, which represented an 11.0% increase in such revenues. This increase is due to: (i) an increase in the electricity rates in our Amatitlan and Puna power plants, which resulted in an increase in the average rate of our electricity portfolio from $78 per MWh in the year ended December 31, 2010 to $83 per MWh in the year ended December 31, 2011; and (ii) increased electricity generation of our power plants from 3,762,283 MWh in the year ended December 31, 2010 to 3,918,156 MWh in the year ended December 31, 2011, an increase of 4.1%. The most significant contributors to the increase in our electricity generation were: (i) an increase in the generation of the Puna power plant due to repair work that was completed in the second quarter of 2010; (ii) the consolidation of the Mammoth complex, effective August 2, 2010, with revenues of $19.0 million in the year ended December 31, 2011, compared to $7.6 million in the period from August 2, 2010 to December 31, 2010, which resulted from the acquisition of the remaining 50% interest in Mammoth Pacific in August 2010; and (iii) an increase in generation of our REG facilities due to the addition of one plant and a higher availability of the pipeline providing the heat to most of our REG power plants. Revenues derived from the North Brawley power plant were $15.3 million and $15.0 million, respectively, in the years ended December 31, 2011 and 2010.

Product Segment

Revenues attributable to our Product Segment for the year ended December 31, 2011 were $113.2 million, compared to $81.4 million for the year ended December 31, 2010, which represented a 39.0% increase in such revenues. The increase in our product revenues reflects the increase in new customer orders that we secured in the first half of 2011, and the recognition of $12.1 million of revenues relating to an LNG energy recovery unit in Spain in the year ended December 31, 2011 (see Research and Development Expenses below).

Total Cost of Revenues

Total cost of revenues for the year ended December 31, 2011 increased by 8.3% to $320.1 million, compared to $295.6 million for the year ended December 31, 2010. This increase is attributable to both our Electricity and Product Segments cost of revenues. As a percentage of total revenues, our total cost of revenues for the year ended December 31, 2011 was 73.2%, compared to 79.2% for the year ended December 31, 2010.

Electricity Segment

Total cost of revenues attributable to our Electricity Segment for the year ended December 31, 2011 increased by 0.7% to $244.0 million, compared to $242.3 million for the year ended December 31, 2010. Costs incurred in operating and maintaining the North Brawley power plant in the year ended December 31, 2011 were slightly higher than in the year ended December 31, 2010 ($41.8 million and $39.6 million, respectively). The overall cost per MWh for the year ended December 31, 2011 slightly decreased, compared to the year ended December 31, 2010, as a result of lower maintenance costs, which were offset by: (i) the slightly higher costs in the North Brawley power plant, as described above; and (ii) increased depreciation costs in the Mammoth complex, resulting from the program to repower the complex by replacing part of the old units with new equipment. As a percentage of total electricity revenues, the total cost of revenues attributable to our Electricity

Segment for the year ended December 31, 2011 was 75.4%, compared to 83.0% for the year ended December 31, 2010. This decrease in electricity cost of revenues as a percentage of total electricity revenues is due to the 11.0% increase in electricity revenues, which outpaced the 0.7% increase in electricity cost of revenues.

Product Segment

Total cost of revenues attributable to our Product Segment for the year ended December 31, 2011 increased by 42.8% to $76.1 million, compared to $53.3 million for the year ended December 31, 2010. This increase is attributable to the increase in product revenues, as described above. As a percentage of total Product Segment revenues, our total cost of revenues attributable to this segment increased from 65.4% for the year ended December 31, 2010 to 67.2% for the year ended December 31, 2011. This increase is mainly attributable to: (i) a different product mix; and (ii) different margins in the various sales contracts. The increase was partially offset by the impact of revenues of $12.1 million relating to an LNG energy recovery unit in Spain with virtually no associated cost of revenues, as these costs had been included in our research and development expenses in previous years.

Research and Development Expenses

Research and development expenses for the year ended December 31, 2011 decreased by 13.0% to $8.8 million, compared to $10.1 million for the year ended December 31, 2010. This decrease is primarily attributable to the decrease in costs related to an experimental REG plant specifically designed to use the residual energy from the vaporization process at LNG regasification terminals. These costs included developing and building a unit at a customer s premises in Spain and were incurred through the second quarter of 2010. Our research and development activities during the year ended December 31, 2011 also included: (i) continued development of EGS; and (ii) activities intended to improve plant performance, reduce costs, and increase the breadth of product offerings. The research and development expenses are net of grants from the DOE in the amount of $1.1 million and $0.7 million for the years ended December 31, 2011 and 2010, respectively, with respect to the EGS project. The primary focus of our research and development efforts includes continued improvements to our Evaporative Cooling system, condensing equipment with improved performance and lower land usage, developing new turbine products, and specialized power units designed to reduce fuel consumption and associated costs during a project s development phase.

Selling and Marketing Expenses

Selling and marketing expenses for the year ended December 31, 2011 were $16.2 million, compared to $13.4 million for the year ended December 31, 2010, which represented a 20.5% increase. The increase was due primarily to the increase in Product Segment revenues and to a $1.7 million termination fee to NV Energy as part of the termination agreement of the PPA and joint operating agreement for the Carson Lake geothermal project. Selling and marketing expenses for the year ended December 31, 2011 constituted 3.7% of total revenues for such period, compared to 3.6% for the year ended December 31, 2010.

General and Administrative Expenses

General and administrative expenses for the year ended December 31, 2011 were $27.9 million, compared to $27.4 million for the year ended December 31, 2010, which represented a 1.6% increase. General and administrative expenses for the year ended December 31, 2011, constituted 6.4% of total revenues for such year, compared to 7.4% for the year ended December 31, 2010.

Write-off of Unsuccessful Exploration Activities

Write-off of unsuccessful exploration activities for the year ended December 31, 2010 was $3.1 million, which represented the write-off of exploration costs related to the Gabbs Valley exploration project in Nevada, which we determined in the second quarter of 2010 would not support commercial operations. There were no write-offs of unsuccessful exploration activities for the year ended December 31, 2011.

Table of Contents

Operating Income

Operating income for the year ended December 31, 2011 was $64.0 million, compared to $23.6 million for the year ended December 31, 2010. This increase of $40.4 million in operating income was principally attributable to an increase in our gross margin due to the increase in revenues, as described above, and the absence of any write-off of unsuccessful exploration activities in the year ended December 31, 2011. Operating income attributable to our Electricity Segment for the year ended December 31, 2011 was $46.2 million, compared to $12.8 million for the year ended December 31, 2010. Operating income attributable to our Product Segment for the year ended December 31, 2011 was $18.9 million, compared to $10.8 million for the year ended December 31, 2010.

Interest Expense, Net

Interest expense, net, for the year ended December 31, 2011 was $69.5 million, compared to $40.5 million for the year ended December 31, 2010, which represented a 71.6% increase. The $29.0 million increase is primarily due to: (i) a $16.4 million loss on interest rate lock transactions in the year ended December 31, 2011, relating to the DOE loan guarantee transactions that were consummated in September 2011, and which were not accounted for as hedge transactions; and (ii) the issuance of Senior Unsecured Bonds in August 2010 and February 2011, as discussed elsewhere in this Item. The increase was partially offset by: (i) an increase of $2.2 million in interest capitalized to projects as a result of increased aggregate investment in projects under construction; and (ii) a decrease in interest expense as a result of principal repayments.

Foreign Currency Translation and Transaction Gains (Losses)

Foreign currency translation and transaction losses for the year ended December 31, 2011 were $1.4 million, compared to gains of $1.6 million for the year ended December 31, 2010. The $3.0 million variance is primarily due to losses on forward foreign exchange transactions for the year ended December 31, 2011, which were not accounted for as hedge transactions, compared to gains in the year ended December 31, 2010.

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, 2011 was $11.5 million, compared to $8.7 million for the year ended December 31, 2010. This income represents the value of PTCs and taxable income or loss generated by OPC and allocated to the investors. The increase resulted from the sale of Class B membership units of OPC LLC to JPM Capital Corporation on February 3, 2011.

Gain on Acquisition of Controlling Interest

Gain on acquisition of controlling interest for the year ended December 31, 2010 was $36.9 million. This gain relates to the acquisition of the remaining 50% interest in Mammoth Pacific. The acquisition-date fair value of the previous 50%-equity interest was $64.9 million. In the year ended December 31, 2010, we recognized a pre-tax gain of $36.9 million ($22.4 million after tax), which is equal to the difference between the acquisition-date fair value of the initial investment in Mammoth Pacific and the acquisition-date carrying value of such investment.

Income Taxes

Income tax provision for the year ended December 31, 2011 was $48.5 million, compared to an income tax benefit of $1.1 million for the year ended December 31, 2010.

In the year ended December 31, 2011, we recorded valuation allowance in the amount of approximately $61.5 million 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, 2011 we have U.S. NOL in the amount of approximately $349.5 million, state NOLs in the amount of approximately $159.0 million, and unutilized tax credits of approximately $61.9 million, that can be utilized over 20 years. The related deferred tax assets totaled approximately $192.5 million. Realization of these deferred tax assets and tax credits is dependent on generating sufficient taxable income in the U.S. prior to expiration of the NOL carryforwards and tax credits. The scheduled reversal of deferred tax liabilities, projected future taxable income and tax planning strategies were considered in determining the amount of valuation allowance. A valuation allowance in the amount of $61.5 million was recorded against the U.S. deferred tax assets as of December 31, 2011 as, at this point in time, 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

Loss from continuing operations for the year ended December 31, 2011 was $42.7 million, compared to income of $32.9 million for the year ended December 31, 2010. This decrease of $75.6 million in income from continuing operations was principally attributable to: (i) the increase of $49.6 million in tax provision resulting from the valuation allowance discussed above; (ii) a $36.9 million gain related to the acquisition of controlling interest in the year ended December 31, 2010; (iii) a $29.0 million increase in interest expense, net; and (iv) a $2.9 million decrease in foreign currency transaction and translation gains. This was partially offset by a $40.4 million increase in operating income.

Discontinued Operations

In January 2010, a former shareholder of GDL exercised a call option to purchase from us our shares in GDL for approximately $2.8 million. We did not exercise our right of first refusal, and therefore we transferred our shares in GDL to the former shareholder. As a result, we recorded an after-tax gain of $4.3 million in the year ended December 31, 2010. The operations of GDL have been included in discontinued operations for all periods prior to the sale of GDL in January 2010.

Net Income (Loss)

Net loss for the year ended December 31, 2011 was $42.7 million, compared to net income of $37.2 million for the year ended December 31, 2010, which represents a decrease of $79.9 million. This decrease in net income was principally attributable to the decrease in income from continuing operations in the amount of $75.6 million, as discussed above.

Comparison of the Year Ended December 31, 2010 and the Year Ended December 31, 2009

Total Revenues

Total revenues for the year ended December 31, 2010 were $373.2 million, compared to $412.0 million for the year ended December 31, 2009, which represented a 9.4% decrease in total revenues. This decrease is attributable to our Product Segment whose revenues decreased by 48.9% from the same period in 2009 (for the reasons discussed below). Revenues in our Electricity Segment increased by 15.5% from the same period in 2009.

Electricity Segment

Revenues attributable to our Electricity Segment for the year ended December 31, 2010 were $291.8 million, compared to $252.6 million for the year ended December 31, 2009, which represented a 15.5% increase in such revenues. The increase is primarily a result of increased electricity generation at most of our power plants from 3,296,824 MWh in the year ended December 31, 2009 to 3,762,283 MWh in the year ended December 31, 2010, an increase of 14.1%. The most significant contributors to the increase in our electricity revenues were:

(i) an increase in the generation of the Puna power plant following repair work that was completed in the second quarter of 2010; (ii) the placement in service of our North Brawley power plant in January 2010, with revenues of $15.0 million in the year ended December 31, 2010; and (iii) the consolidation of the Mammoth complex, effective August 2, 2010, with revenues of $7.6 million in the period from August 2, 2010 to December 31, 2010, resulting from the acquisition of the remaining 50% interest in Mammoth Pacific. The increase in our Electricity Segment revenues is also attributable to a slight increase in the average revenue rate of our electricity portfolio from $77 per MWh in the year ended December 31, 2009 to $78 per MWh in the year ended December 31, 2010.

Product Segment

Revenues attributable to our Product Segment for the year ended December 31, 2010 were $81.4 million, compared to $159.4 million for the year ended December 31, 2009, which represented a 48.9% decrease in such revenues. This decrease in our product revenue is a result of reduced Product Segment customer orders for the year ended December 31, 2010.

Total Cost of Revenues

Total cost of revenues for the year ended December 31, 2010 was $295.6 million, compared to $291.6 million for the year ended December 31, 2009, which represented a 1.4% increase in total cost of revenues. This increase is attributable to an increase in our Electricity Segment cost of revenues, which was offset by a decrease in our Product Segment cost of revenues, as discussed below. As a percentage of total revenues, our total cost of revenues for the year ended December 31, 2010 was 79.2%, compared to 70.8% for the year ended December 31, 2009. This increase is mainly attributable to high costs in our North Brawley power plant, as described below, as well as the lower volume of Product Segment revenues.

Electricity Segment

Total cost of revenues attributable to our Electricity Segment for the year ended December 31, 2010 was $242.3 million, which include $39.6 million related to our North Brawley power plant, compared to $179.1 million for the year ended December 31, 2009, which represented a 35.3% increase in total cost of revenues for such segment. The increase over the same period last year is mainly attributable to our North Brawley power plant which was placed in service in January 2010. We have incurred high costs (including depreciation) associated with operating and maintaining this power plant, which has a design capacity of 50 MW but is currently operating at a reduced capacity. The higher costs in the North Brawley power plant increased the cost per MWh for the year ended December 31, 2010, compared to the year ended December 31, 2009. As a percentage of total electricity revenues, the total cost of revenues attributable to our Electricity Segment for the year ended December 31, 2010 was 83.0%, compared to 70.9% for the year ended December 31, 2009.

Product Segment

Total cost of revenues attributable to our Product Segment for the year ended December 31, 2010 was $53.3 million, compared to $112.5 million for the year ended December 31, 2009, which represented a 52.6% decrease in total cost of revenues related to such segment. This decrease is attributable to the decrease 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, 2010 decreased from 70.6% for the year ended December 31, 2009 to 65.4% for the year ended December 31, 2010. This percentage decrease is attributable to the removal of a contingency relating to a project that was substantially completed in the second quarter of 2010.

Research and Development Expenses

Research and development expenses for the year ended December 31, 2010 were $10.1 million, compared to $10.5 million for the year ended December 31, 2009, which represented a 3.6% decrease. Our research and development activities during the year ended December 31, 2010 included primarily: (i) an experimental REG plant specifically designed to use the residual energy from the vaporization process at LNG regasification terminals, including developing and building a unit at a customer s premises in Spain; (ii) continued development of EGS; and (iii) development of a solar thermal system for the production of electricity. Construction of the experimental REG plant commenced in the third quarter of 2010 and was completed during the fourth quarter of 2011. The research and development expenses are net of grants from the DOE in the amount of $0.7 million and $1.3 million for the years ended December 31, 2010 and 2009, respectively, with respect to the EGS project.

Selling and Marketing Expenses

Selling and marketing expenses for the year ended December 31, 2010 were $13.4 million, compared to $14.6 million for the year ended December 31, 2009, which represented a 7.8% decrease. The decrease was due primarily to the decrease in Product Segment revenues. Selling and marketing expenses for the year ended December 31, 2010 constituted 3.6% of total revenues for such period, compared to 3.5% for the year ended December 31, 2009.

General and Administrative Expenses

General and administrative expenses for the year ended December 31, 2010 were $27.4 million, compared to $26.4 million for the year ended December 31, 2009, which represented a 3.9% increase. General and administrative expenses for the year ended December 31, 2010 constituted 7.4% of total revenues for such year, compared to 6.4% for the year ended December 31, 2009.

Write-off of Unsuccessful Exploration Activities

Write-off of unsuccessful exploration activities for the year ended December 31, 2010 was $3.1 million, compared to $2.4 million for the year ended December 31, 2009. Write-off of unsuccessful exploration activities for the year ended December 31, 2010 relates to the Gabbs Valley exploration project in Nevada, which we determined in the second quarter of 2010 would not support commercial operations. Write-off of unsuccessful exploration activities for the year ended December 31, 2009 relates to the Rock Hills exploration project in Nevada, which we determined in the third quarter of 2009 would not support commercial operations.

Operating Income

Operating income for the year ended December 31, 2010 was $23.6 million, compared to $66.6 million for the year ended December 31, 2009. Such decrease of $43.0 million in operating income was principally attributable to a decrease in the total gross margin due to the decrease in Product Segment revenues and the increase in Electricity Segment cost of revenues. Operating income attributable to our Electricity Segment for the year ended December 31, 2010 was $12.8 million, compared to $45.3 million for the year ended December 31, 2009, mainly due to the increase in electricity cost of revenues, as explained above. Operating income attributable to our Product Segment for the year ended December 31, 2010 was $10.8 million, compared to $21.3 million for the year ended December 31, 2009, mainly due to the decrease in product revenues, as explained above.

Interest Expense, Net

Interest expense, net, for the year ended December 31, 2010 was $40.5 million, compared to $16.2 million for the year ended December 31, 2009, which represented a 149.2% increase. The $24.2 million increase is primarily due to: (i) a decrease of $17.9 million in interest capitalized to projects as a result of decreased aggregate investment in projects under construction; (ii) an increase in interest expenses related to our long-term project finance loans of the Olkaria III and Amatitlan power plants; (iii) borrowings under our revolving credit

Table of Contents

lines with commercial banks; (iv) loan agreements with institutional investors and a commercial bank; and (v) issuance of Senior Unsecured Bonds on August 3, 2010, as discussed below. The increase was partially offset by a decrease in interest expense as a result of the acquisition of a 30% interest in the Class B membership units of OPC on October 30, 2009 by our subsidiary, Ormat Nevada, as well as principal repayments.

Foreign Currency Translation and Transaction Gains (Losses)

Foreign currency translation and transaction gains for the year ended December 31, 2010 were $1.6 million, compared to losses of $1.7 million for the year ended December 31, 2009. The $3.3 million increase is primarily due to an increase in gains on forward foreign exchange transactions 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 below) for the year ended December 31, 2010 was $8.7 million, compared to $15.5 million for the year ended December 31, 2009. This income represents the value of PTCs and taxable income or loss generated by OPC and allocated to the investors. The decrease is due to lower depreciation for tax purposes as a result of declining depreciation rates utilizing MACRS and to the purchase of Class B membership units of OPC from Lehman-OPC LLC (Lehman OPC) in October 2009, as described under Gain from Extinguishment of Liability below.

Gain on Acquisition of Controlling Interest

Gain on acquisition of controlling interest for the year ended December 31, 2010 was $36.9 million. This gain relates to the acquisition of the remaining 50% interest in Mammoth Pacific. The acquisition-date fair value of the previous 50%-equity interest was $64.9 million. In the year ended December 31, 2010, we recognized a pre-tax gain of $36.9 million ($22.4 million after tax), which is equal to the difference between the acquisition-date fair value of the initial investment in Mammoth Pacific and the acquisition-date carrying value of such investment.

Gain from Extinguishment of Liability

Gain from extinguishment of liability for the year ended December 31, 2009 was $13.3 million. On October 30, 2009, Ormat Nevada acquired Lehman-OPC s 30% interest in the Class B membership units of OPC. The membership units were acquired from 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. As a result, the repurchase of these interests at a discount resulted in a pre-tax gain of $13.3 million ($8.2 million after tax) in the year ended December 31, 2009. In addition, an amount of approximately $1.1 million was classified in the year ended December 31, 2009 from noncontrolling interest to additional paid-in capital representing the 1.5% residual interest of Lehman-OPC s Class B membership units.

Income Taxes

Income tax benefit for the year ended December 31, 2010 was $1.1 million, compared to income tax provision of $15.4 million for the year ended December 31, 2009. The effective tax rate for the year ended December 31, 2010 was 3.6% compared to 19.7% for the year ended December 31, 2009. The decrease in the effective tax rate primarily resulted from the higher impact of PTCs on the effective tax rate for the year ended December 31, 2010 due to our low pretax income from continuing operations.

Equity in Income of Investees

Our participation in the income generated from our investees for the year ended December 31, 2010 was $1.0 million, compared to $2.1 million for the year ended December 31, 2009. The amount is derived mainly from our 50% ownership of the Mammoth complex which was included in the Company s consolidated financial statements effective August 2, 2010, as a result of our acquisition of the remaining 50% interest in Mammoth Pacific. For the year ended December 31, 2010, the amount represents our share in the income of the Mammoth complex in the period from January 1, 2010 to August 1, 2010.

Income from Continuing Operations

Income from continuing operations for the year ended December 31, 2010 was $32.9 million, compared to $65.1 million for the year ended December 31, 2009. This decrease of $32.2 million in income from continuing operations was principally attributable to: (i) a $43.0 million decrease in operating income; (ii) a $24.2 million increase in interest expense, net; (iii) a $6.8 million decrease in income attributable to the sale of tax benefits; and (iv) gain from extinguishment of liability of $13.3 million in the year ended December 31, 2009. This was partially offset by: (i) a $3.3 million increase in foreign currency transaction and translation gains; (ii) a $36.9 million gain related to the acquisition of controlling interest in the year ended December 31, 2010; and (iii) a $16.5 million decrease in income tax provision.

Discontinued Operations

In January 2010, a former shareholder of GDL exercised a call option to purchase from us our shares in GDL for approximately $2.8 million. We did not exercise our right of first refusal, and therefore we transferred our shares in GDL to the former shareholder. As a result, we recorded an after-tax gain of $4.3 million in the year ended December 31, 2010. The operations of GDL have been included in discontinued operations for all periods prior to the sale of GDL in January 2010.

Net Income

Net income for the year ended December 31, 2010 was $37.2 million, compared to $68.6 million for the year ended December 31, 2009, which represents a decrease of $31.3 million. This decrease in net income was principally attributable to the decrease in income from continuing operations in the amount of $32.2 million, as discussed above.

Liquidity and Capital Resources

Our principal sources of liquidity have been derived from cash flows from operations, the issuance of our common stock in public and private offerings, proceeds from third party debt in the form of borrowings under credit facilities and private offerings, issuance by OFC, OrCal and OFC 2 of their respective Senior Secured Notes, project financing (including the Puna lease and the OPC Transaction described below), and cash grants we received under the ARRA. We have utilized this cash to fund our acquisitions (including the acquisition of the remaining 50% ownership of the Mammoth complex in August 2010), to develop and construct power generation plants, and to meet our other cash and liquidity needs.

As of December 31, 2011, we have access to the following sources of funds: (i) $118.4 million in cash, cash equivalents and marketable securities; and (ii) $75.1 million of unused corporate borrowing capacity under existing lines of credit with different commercial banks.

Our estimated capital needs for 2012 include approximately $367.0 million for capital expenditures on new projects under development or construction, exploration activity, operating projects, and machinery and equipment, as well as $55.6 million for debt repayment.

We expect to finance these requirements with: (i) the sources of liquidity described above; (ii) 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 new projects that will be placed in service before the end of 2013. Management believes that these sources will address our anticipated liquidity, capital expenditures, and other investment requirements.

Table of Contents

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 under the heading 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 under the heading Full-Recourse Third-Party Debt.

Non-Recourse and Limited-Recourse Third-Party Debt

OFC Senior Secured Notes Non-Recourse

On February 13, 2004, OFC, one of our subsidiaries, issued $190.0 million of OFC Senior Secured Notes in an offering subject to Rule 144A and Regulation S of the Securities Act, for the purpose of refinancing the acquisition cost of the Brady, Ormesa and Steamboat 1 and 1A power plants, and the financing of the acquisition cost of the Steamboat 2 and 3 power plants. 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 which commenced on June 30, 2004. 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 a required historical and projected 12-month debt service coverage ratio (DSCR) of not less than 1.25 and other limitations on additional indebtedness. If OFC fails to comply with these financial ratios it will be precluded from making distributions to its shareholders. In addition, subject to certain cure rights, such failure will constitute an event of default by OFC. As of December 31, 2011, the actual historical 12-month DSCR was 1.49. As of December 31, 2011, there were $125.0 million of OFC Senior Secured Notes outstanding.

OrCal Geothermal Senior Secured Notes Non-Recourse

On December 8, 2005, OrCal, one of our subsidiaries, issued $165.0 million of OrCal Senior Secured Notes in an offering subject to Rule 144A and Regulation S of the Securities Act, for the purpose of refinancing the acquisition cost of the Heber projects. The OrCal Senior Secured Notes have been rated BBB- by Fitch. 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 that commenced on June 30, 2006. 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 a required historical and projected 12-month DSCR of not less than 1.25 and other limitations on additional indebtedness. If OrCal fails to comply with these financial ratios it will be precluded from making distributions to its shareholders. In addition, subject to certain cure rights, such failure will constitute an event of default by OrCal. As of December 31, 2011, the actual historical 12-month DSCR was 2.02. As of December 31, 2011, there were $85.9 million of OrCal Senior Secured Notes outstanding.

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

On September 23, 2011, OFC 2, one of our subsidiaries, and its wholly owned project subsidiaries (collectively, the 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

Table of Contents

the Jersey Valley, McGinness Hills and Tuscarora geothermal power facilities owned by the 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 in accordance with an amortization schedule attached to such Notes 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 (the DOE Guarantee) 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 the DOE Guarantee.

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 $147.4 million, and were used to finance a portion of the construction costs of Phase I of the McGinness Hills and Tuscarora facilities and to fund certain reserves. Interest on the Series A Notes is payable quarterly in arrears on the last day of March, June, September and December, commencing December 31, 2011. Principal on the Series A Notes is payable on the same quarterly dates, commencing September 30, 2012.

Issuance of the Series B Notes is dependent on the Jersey Valley facility 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 facility.

The Issuers have sole discretion regarding whether to commence construction of Phase II of any of the Jersey Valley, McGinness Hills and Tuscarora facilities. If Phase II construction is undertaken for any of the facilities, the Issuers may issue Phase II tranches of Notes, comprised of one or more of the Series C Notes, the Series D Notes, the Series E Notes and the 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 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 a required 12-month DSCR of not less than 1.65 and other limitations on additional indebtedness and payment of dividends. The covenants will become effective after completion of construction of the McGinness Hills and Tuscarora facilities.

In addition, in connection with the issuance of each Series of OFC 2 Senior Secured Notes, we will provide a guarantee with respect to the OFC 2 Senior Secured Notes, which will be available to be drawn upon if specific 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 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 Issuers into compliance with certain coverage ratios. A demand on our guarantee based on the other trigger event is not so limited.

As of December 31, 2011, there were $151.7 million of OFC 2 Senior Secured Notes outstanding.

Table of Contents

Olkaria III Loan Non-Recourse

OrPower 4 has a project financing loan of $105.0 million to refinance its investment in the 48 MW Olkaria III complex located in Kenya. The loan was provided by a group of European DFIs arranged by DEG. The 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 $77.0 million of the loan at 6.90%. There are various restrictive covenants under the loan, including a requirement to comply with the following financial ratios for each calculation period: (i) an historical and projected 12-month DSCR of not less than 1.15; (ii) a debt to equity ratio which does not exceed 3; and (iii) an equity to total assets ratio of not less than 0.25. If OrPower 4 fails to comply with these financial ratios it will be precluded from making distributions to its shareholders. In addition, subject to certain cure rights, such failure will constitute an event of default by OrPower 4. As of December 31, 2011: (i) the actual 12-month historical DSCR was 2.34; (ii) the debt to equity ratio was 1.3; and (iii) the equity to total assets ratio was 0.34. As of December 31, 2011, $77.4 million of the above loan was outstanding.

We plan to refinance the existing Olkaria III Loan as described under New Financing of our Projects below.

Amatitlan Loan Non-Recourse

In May 2009, Ortitlan entered into a note purchase agreement in an aggregate principal amount of $42.0 million to refinance its investment in the 20 MW Amatitlan geothermal power plant located in Amatitlan, Guatemala. The loan was provided by TCW Global Project Fund II, Ltd. The loan will mature on June 15, 2016, and is payable in 28 quarterly installments. The annual interest rate on the loan is 9.83%, but the effective cost for us is approximately 8%, due to the elimination, following the refinancing, of the political risk insurance premiums that we had been paying on our equity investment in the power plant. There are various restrictive covenants under the Amatitlan Loan, which include a projected 12-month DSCR of not less than 1.2, a long-term debt to equity ratio not to exceed 4.0 and other limitations on Ortitlan s ability to make distributions to its shareholders. If Ortitlan fails to comply with these financial ratios it will be precluded 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, 2011, the actual projected 12-month DSCR was 1.54 and the debt to equity ratio was 2.67. As of December 31, 2011, $36.8 million of the above loan was outstanding.

New Financing of our Projects

Refinancing of the Olkaria III Loan and Financing of the Construction of the Olkaria III Complex Expansion

In September 2011, Ormat International, one of our subsidiaries, signed a commitment letter with OPIC to provide project financing of up to $310.0 million to refinance and expand our 48 MW Olkaria III complex located in Kenya. Under the agreed term sheet attached to the commitment letter, the loan will be comprised of a refinancing tranche of up to $85.0 million to prepay the existing loan with DEG and fund transaction costs, a construction loan tranche of up to $165.0 million to finance the construction of an additional 36 MW expansion currently underway, and a $60.0 million stand-by facility to finance an additional 16 MW capacity expansion at our option, that, if exercised by us, could bring the total capacity of the complex to approximately 100 MW. The maturity dates of the construction tranche and the refinancing tranche are expected to be June 2030 and December 2030, respectively. The maturity date and certain other terms of the stand-by facility will be finalized following our decision, if any, to exercise the option to construct the additional 16 MW expansion.

Full-Recourse Third-Party Debt

In December 2008, our wholly owned subsidiary, Ormat Nevada, entered into an amendment to its credit agreement with Union Bank. Under the amendment, the credit termination date was extended to February 15, 2012 and the aggregate amount available under the credit agreement was increased to $37.5 million. Under the credit agreement, as amended, Ormat Nevada could request extensions of credit in the form of loans and/or the issuance of one or more letters of credit. In August 2011, the credit agreement was further amended to increase the credit line to $39.0 million. On February 7, 2012, Ormat Nevada entered into an amended and restated credit agreement with Union Bank to increase the available credit to $50.0 million and extend the termination date to February 7, 2014. 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 have 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.

Draws under the credit agreement will bear interest at a floating rate based on the Eurodollar plus a margin. There are various restrictive covenants under the credit agreement, which include; (i) minimum tangible net worth assets of not less than $164.0 million; (ii) 12-month debt to EBITDA ratio not to exceed 5; and (iii) 12-month DSCR of not less than 1.25. As of December 31, 2011: (i) the actual tangible net worth assets of Ormat Nevada was $1.4 billion; (ii) the 12-month debt to EBITDA ratio was 3.45; and (iii) the DSCR was 2.69. 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.

Under the February 7, 2012 amendment to the credit agreement, the restrictive covenants were amended to the following: (i) 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.

As of December 31, 2011, letters of credit in the aggregate amount of $32.5 million remain issued and outstanding under this credit agreement with Union Bank.

We also have credit agreements with five commercial banks for an aggregate amount of $370.0 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 $265.0 million; and (ii) the issuance of one or more letters of credit in the amount of up to $105.0 million. The credit agreements mature between December 2012 and December 2014. 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, 2011, loans in the total amount of $214.0 million (including $10.0 million under a non-committed line of credit with an additional commercial bank) were outstanding, and letters of credit with an aggregate stated amount of $97.4 million were issued and outstanding under these credit agreements. The $214.0 million in loans are for terms of three months or less and bear interest at a weighted average rate of 3.32%.

We have a $20.0 million term loan with a group of institutional investors, which matures on July 16, 2015, is payable in twelve semi-annual installments commencing January 16, 2010, and bears interest of 6.5%. As of December 31, 2011, $14.2 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 twelve semi-annual installments commencing February 1, 2012, and bears interest at 6-month LIBOR plus 5.0%. As of December 31, 2011, $20.0 million was outstanding under this loan.

We have a $20.0 million term loan with a group of institutional investors, which matures on November 16, 2016, is payable in ten semi-annual installments commencing May 16, 2012, and bears interest of 5.75%. As of December 31, 2011, $20.0 million was outstanding under this loan.

Table of Contents

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, 2011, $30.0 million was outstanding under this loan.

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%, 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%. We issued the bonds outside the United States to investors who are not U.S. persons in an unregistered offering pursuant to, and subject to the requirements of, Regulation S under the Securities Act.

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 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, such as: (i) stockholders 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 marketable securities to EBITDA ratio not to exceed 7; and (iii) dividend distribution not to exceed 35% of net income for that year. As of December 31, 2011, the actual equity to total assets ratio was 39.2%, the stockholders equity was $906.6 million, and the 12-month debt, net of cash, cash equivalents and marketable securities to EBITDA ratio was 5.42. 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 plan of 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, 2011, letters of credit in the aggregate amount of $196.6 million remained issued and outstanding (out of which $129.9 million were issued under the credit agreements with Union Bank and five of the commercial banks as described under Full-Recourse Third Party Debt and $66.7 million were issued under non-committed lines of credit).

Puna Power Plant Lease Transactions

On May 19, 2005, our subsidiary in Hawaii, PGV, entered into a transaction involving the Puna geothermal power plant located on the Big Island of Hawaii. 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, our 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), 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.

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 it recovers the capital that it 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 terms of the transaction. Once the investors reach a target after-tax yield on their investment in OPC (the Flip Date), Ormat Nevada will receive 95% of both distributable cash and taxable income, on a going forward basis. Following the 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.

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 Flip Date. The actual 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.

Our voting rights in OPC are based on a capital structure that is comprised of Class A and Class B membership units. We own, through our subsidiary, Ormat Nevada, 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 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 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 Flip Date and therefore has continued to consolidate OPC.

On October 30, 2009, Ormat Nevada acquired from Lehman-OPC all of the Class B membership units of OPC held by Lehman-OPC pursuant to a right of first offer for a purchase price of $18.5 million in cash.

On February 3, 2011, Ormat Nevada sold to JPM Capital Corporation all of the Class B membership units of OPC that it had acquired on October 30, 2009 for a sale price of $24.9 million in cash.

Liquidity Impact of Uncertain Tax Positions

As discussed in Note 19 to our consolidated financial statements set forth in Part II, Item 8 of this annual report, we have a liability associated with unrecognized tax benefits and related interest and penalties in the

Table of Contents

amount of approximately $5.9 million as of December 31, 2011. 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, but do not believe that the ultimate settlement of our obligations will materially affect our liquidity.

Dividend

The following are the dividends declared by us during the past two years:

Date Declared	Dividend Amount per Share	Record Date	Payment Date
February 23, 2010	$ 0.12	March 16, 2010	March 25, 2010
May 5, 2010	$ 0.05	May 18, 2010	May 25, 2010
August 4, 2010	$ 0.05	August 17, 2010	August 26, 2010
November 2, 2010	$ 0.05	November 17, 2010	November 30, 2010
February 22, 2011	$ 0.05	March 15, 2011	March 24, 2011
May 4, 2011	$ 0.04	May 18, 2011	May 25, 2011
August 3, 2011	$ 0.04	August 16, 2011	August 25, 2011

Historical Cash Flows

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

	Year Ended December 31,		
	2011	2010	2009
		(In thousands)	
Net cash provided by operating activities	$ 132,734	$ 101,403	$ 110,772
Net cash used in investing activities	(341,002)	(203,820)	(286,036)
Net cash provided by financing activities	225,339	138,925	187,036
Translation adjustments on cash and cash equivalents			142
Net change in cash and cash equivalents	17,071	36,508	11,914

For the Year Ended December 31, 2011

Net cash provided by operating activities for the year ended December 31, 2011 was $132.7 million, compared to $101.4 million for the year ended December 31, 2010. The net increase of $31.3 million resulted primarily from: (i) an increase of $9.7 million in depreciation and amortization, as described above; (ii) a gain on acquisition of controlling interest in the Mammoth complex of $36.9 million in the year ended December 31, 2010; (iii) a gain on sale of GDL of $6.3 million in the year ended December 31, 2010; (iv) an increase in deferred income tax provision, net of $38.1 million in the year ended December 31, 2011, compared to a decrease of $10.1 million in the year ended December 31, 2010; and (v) an increase in billing in excess of costs and estimated earnings on uncompleted contracts, net of $32.1 million in our Product Segment in the year ended December 31, 2011, compared to $8.7 million in the year ended December 31, 2010, as a result of timing in billing of our customers. Such increase was partially offset by: (i) a net loss to $42.7 million in the year ended December 31, 2011, compared to net income of $37.2 million in the year ended December 31, 2010, as described above, and (ii) an increase in accounts payable and accrued expenses of $5.5 million in the year ended December 31, 2011, compared to an increase of $9.7 million in the year ended December 31, 2010, as a result of timing of payments to our vendors.

Net cash used in investing activities for the year ended December 31, 2011 was $341.0 million, compared to $203.8 million for the year ended December 31, 2010. The principal factors that affected our net cash used in

Table of Contents

investing activities during the year ended December 31, 2011 were: (i) capital expenditures of $269.7 million, primarily for our facilities under construction; (ii) net increase of $50.6 million in restricted cash, cash equivalents and marketable securities as a result of the issuance of the OFC 2 Senior Secured Notes, and (iii) net increase of $17.5 million in marketable securities.

Net cash provided by financing activities for the year ended December 31, 2011 was $225.3 million, compared to $138.9 million for the year ended December 31, 2010. The principal factors that affected the net cash provided by financing activities during the year ended December 31, 2011 were: (i) the issuance of an aggregate amount of approximately $107.4 million of Senior Unsecured Bonds in February 2011; (ii) $141.1 million net proceeds from the issuance of the OFC 2 Senior Secured Notes; (iii) proceeds from the sale of all of the Class B membership units of OPC acquired on October 30, 2009 for a sale price of 24.9 million in February 2011; and (iv) a net increase of $24.6 million against our revolving lines of credit with commercial banks; offset by: (i) the repayment of long-term debt in the amount of $48.4 million; (ii) cash paid to noncontrolling interest in the amount of $14.0 million; and (iii) the payment of a dividend to our shareholders in the amount of $5.9 million.

For the Year Ended December 31, 2010

Net cash provided by operating activities for the year ended December 31, 2010 was $101.4 million, compared to $110.8 million for the year ended December 31, 2009. The net decrease of $9.4 million resulted primarily from: (i) a decrease in net income to $37.2 million in the year ended December 31, 2010, from $68.6 million in the year ended December 31, 2009, mainly as a result of the decrease in operating income, as described above; (ii) a gain on acquisition of controlling interest of $36.9 million in the year ended December 31, 2010; (iii) a gain on sale of GDL of $6.4 million in the year ended December 31, 2010; and (iv) a net decrease in deferred income taxes of $10.1 million in the year ended December 31, 2010, compared to a net increase of $4.0 million in the year ended December 31, 2009. Such decrease was partially offset by: (i) an increase of $22.4 million in depreciation and amortization mainly due to the placement in service of our North Brawley power plant in January 2010, as described above; (ii) a gain from extinguishment of liability of $13.3 million in the year ended December 31, 2009; (iii) a net decrease in costs and estimated earnings in excess of billings on uncompleted contracts of $8.7 million in the year ended December 31, 2010, compared to a net increase of $20.0 million in the year ended December 31, 2009; and (iv) an increase in accounts payable and accrued expenses of $9.7 million in the year ended December 31, 2010, compared to a decrease of $2.1 million in the year ended December 31, 2009.

Net cash used in investing activities for the year ended December 31, 2010 was $203.8 million, compared to $286.0 million for the year ended December 31, 2009. The principal factors that affected our net cash used in investing activities during the year ended December 31, 2010 were: (i) capital expenditures of $283.3 million, primarily for our facilities under construction; and (ii) net payment of $64.5 million for acquisition of controlling interest in Mammoth Pacific ($72.5 million purchase price less $8.0 million available cash in such subsidiary at the acquisition date); offset by: (i) $108.3 million of cash grant received in September 2010 for Specified Energy Property in Lieu of Tax Credits relating to our North Brawley geothermal power plant under Section 1603 of the ARRA; (ii) $19.6 million cash received from the sale of GDL; and (iii) a $17.5 million decrease in restricted cash, cash equivalents and marketable securities.

Net cash provided by financing activities for the year ended December 31, 2010 was $138.9 million, compared to $187.0 million for the year ended December 31, 2009. The principal factors that affected the net cash provided by financing activities during the year ended December 31, 2010 were: (i) the issuance of an aggregate amount of approximately $142.0 million of Senior Unsecured Bonds on August 3, 2010; (ii) $20.0 million proceeds from a long-term loan agreement with a group of institutional investors; and (iii) $55.5 million increase in amounts drawn under revolving lines of credit from banks; offset by: (i) the repayment of long-term debt to our parent in the amount of $9.6 million; (ii) the repayment of debt to third parties in the amount of $52.2 million; and (iii) the payment of a dividend to our shareholders in the amount of $12.3 million.

Table of Contents

Adjusted EBITDA

We calculate EBITDA as net income before interest, taxes, depreciation and amortization. We calculate adjusted EBITDA to include depreciation and amortization, interest and taxes attributable to our equity investments in the Mammoth complex. 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, 2011 increased to $166.7 million, compared to $164.3 million for the year ended December 31, 2010. Adjusted EBITDA for the year ended December 31, 2010 decreased to $164.3 million, compared to $167.0 million for the year ended December 31, 2009. Adjusted EBITDA includes consolidated EBITDA and our share in the interest, taxes, depreciation and amortization related to our unconsolidated 50% interest in the Mammoth complex in the years ended December 31, 2010 and 2009.

The following table reconciles net cash provided by operating activities to EBITDA and adjusted EBITDA, for the years ended December 31, 2011, 2010, and 2009:

	Year Ended December 31,		
	2011	2010	2009
	(in thousands)		
Net cash provided by operating activities	$ 132,734	$ 101,403	$ 110,772
Adjusted for:			
Interest expense, net (excluding amortization of deferred financing costs)	65,920	37,590	13,623
Interest income	(1,427)	(343)	(639)
Income tax provision (benefit)	48,535	908	16,924
Adjustments to reconcile net income to net cash provided by operating activities (excluding depreciation and amortization)	(79,060)	22,586	22,392
EBITDA	166,702	162,144	163,072
Interest, taxes, depreciation and amortization attributable to the Company s equity interest in Mammoth-Pacific L.P.		2,115	3,891
Adjusted EBITDA	$ 166,702	$ 164,259	$ 166,963
Net cash used in investing activities	$ (341,002)	$ (203,820)	$ (286,036)
Net cash provided by financing activities	$ 225,339	$ 138,925	$ 187,036