ORMAT TECHNOLOGIES, INC.

2019 ANNUAL REPORT

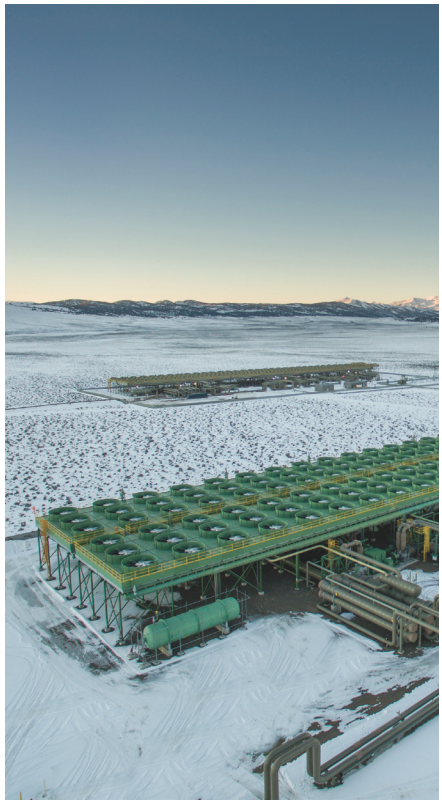
ORMAT

55 years
of experience

746 $M
FY 2019 revenues

384 $M(1)
FY 2019 adj. EBITDA

Own & operate
914 MW



~1,410
Employees

(1) See Adjusted EBITDA reconciliation in Ormat Technologies, Inc. 2019 Annual Report on Form 10-K under Item 7 – "management's discussion and analysis of financial condition and results of operations".

DEAR SHAREHOLDERS,

As I'm writing this letter, the COVID-19 situation is still evolving, and the world is facing a global health crisis and a dramatic volatile economic environment. At Ormat, our first priority is to make sure that all our employees and their families are safe and they are able to navigate this crisis unharmed. we have taken significant steps to protect our employees across the globe addressing their health and safety. In addition, we are managing our cash flow and optimizing our investments and expenses to maintain our strong cash flow position and support our ability to cross this evolving crisis successfully.

In late February we announced our 2019 earnings results and in this letter I'm proud to share with you the strategic and operational achievements we accomplished during 2019 in the face of significant external challenges. I will do so, in what will be my last shareholder letter to you, as I recently announced my intention to retire, effective July 1, 2020, following six successful and fulfilling years as the Chief Executive Officer of Ormat. As part of an organized and thoughtful succession plan, I am grateful to accept our Board's offer to serve as a director on the Company's Board of Directors, and will work with Doron Blachar, our current President and CFO, who will succeed me as CEO in July 1st. Doron and I have worked hand-in-hand for years and I am overwhelmingly confident that he with the support of our strong management team is the right person to lead Ormat into the future.

In 2020 Ormat delivered higher revenues, higher electricity generation, and higher Adjusted EBITDA than in preceding years. With three favorable new PPAs signed, the expected return to operation of Puna, a favorable regulatory landscape and growing contribution from our storage segment, Ormat is exceedingly well-positioned for the long-term future. This was achieved despite the fact that our Puna plant in Hawaii generated no electricity for us in 2019. Due to the volcanic eruption in mid-2018, In the last year we focused our efforts on getting Puna back online, and as we move into 2020, we expect that this plant will return to operation during the second half of 2020.

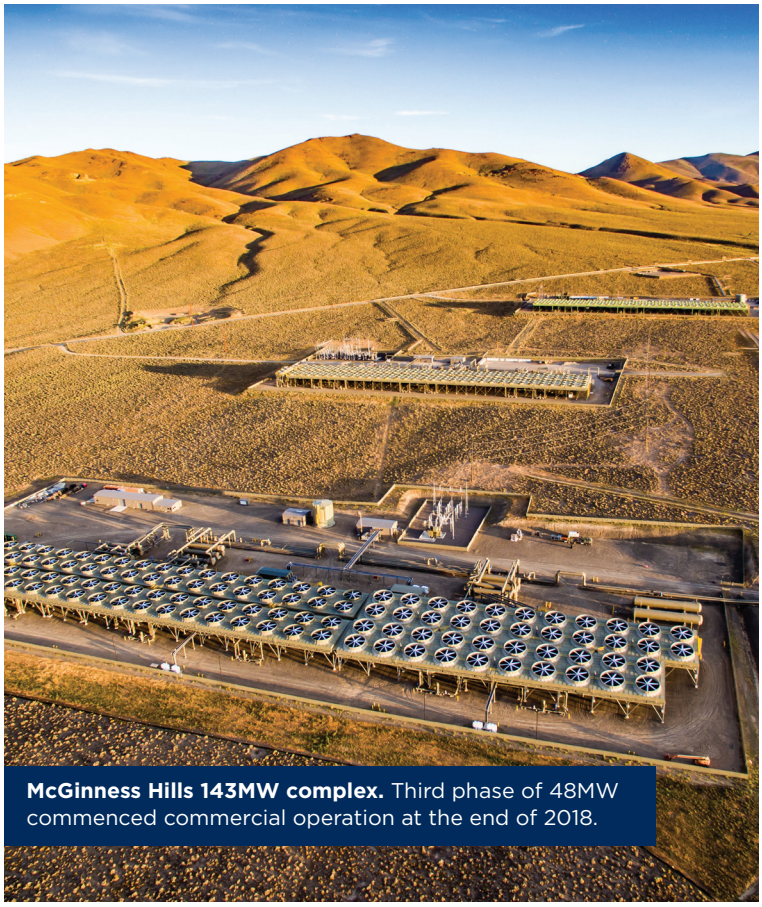
DELIVERING ANOTHER YEAR OF RECORD REVENUES AND PROFITABILITY

Ormat grew both total revenues and electricity revenues, speaking to the diversified and expanded portfolio of assets we have assembled. For the full year 2019, total revenues increased 3.7% year-over-year to $746.0 million and 6.5% year-over-year to $540.3 million in our Electricity segment benefitting from our new plants added to our portfolio, including the third phase of the McGinness Hills Complex, an expansion in Olkaria, the three power plants we acquired as part of the US Geothermal acquisition and the Tungsten solar plant.

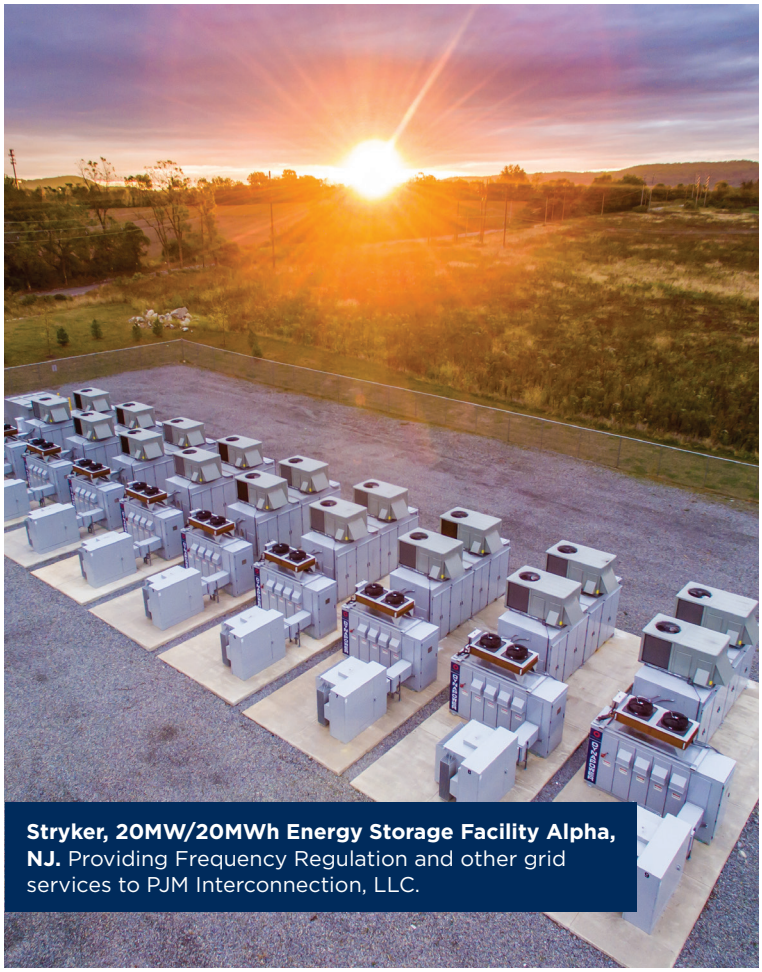
The products segment remains an industry leader and provides Ormat with a competitive differentiator by making us the geothermal industry's only vertically integrated player. We ended the year with a backlog of approximately $142 million, and we are pursuing opportunities around the world, most notably in New Zealand and the Philippines. In Turkey following a cycle of a rapid growth in the geothermal market, the local financial situation is creating a slowdown, leading to lower revenues and a smaller backlog in this segment. We are negotiating contracts in other geographies, though the signing of which may be delayed due to the recent COVID 19 crisis.

In the Energy Storage and Management Services activity, we continue to utilize our engineering expertise, resources, and access to capital to build presence in the energy storage market. Our efforts in battery storage activity remain focused on new project development as well as M&A and joint development opportunities. In 2019 we commissioned two projects in New Jersey and one in Vermont. We are successfully creating a wider portfolio in this market spanning multiple opportunities and regions in the U.S.

Overall, we exceeded our revenue outlook and we met our Adjusted EBITDA outlook which excluded the impact of Puna, delivering $384.3 million for the year, up 4.4% and $385.5 million excluding the impact of Puna. This was a highly successful year for Ormat and I believe we continue to position Ormat for long-term success.

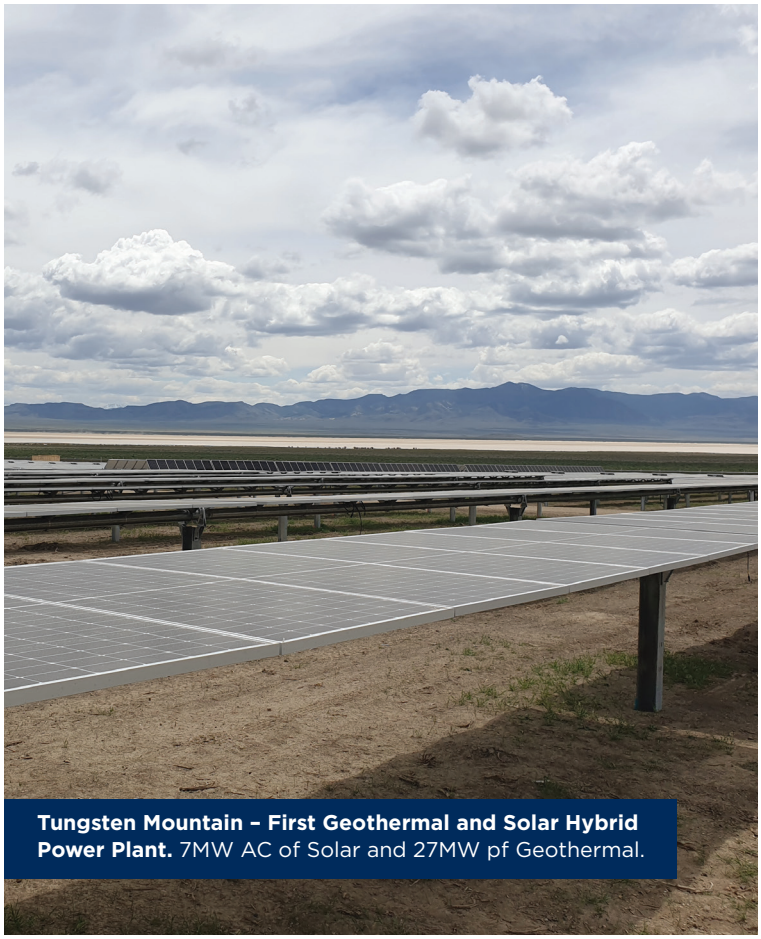


McGinness Hills 143MW complex. Third phase of 48MW commenced commercial operation at the end of 2018.



Stryker, 20MW/20MWh Energy Storage Facility Alpha, NJ. Providing Frequency Regulation and other grid services to PJM Interconnection, LLC.

Zunil, Guatemala – Inauguration of second floor of the local elementary school funded by Ormat, adding junior high school classes.



Tungsten Mountain – First Geothermal and Solar Hybrid Power Plant. 7MW AC of Solar and 27MW pf Geothermal.

ADVANCING SUSTAINABILITY

Our operational success has been achieved with an unwavering commitment to provide renewable energy safely, economically and in an environmentally responsible manner. The current health crisis has put a brighter spotlight on the importance of sustainability. Our Company recognizes the importance of the fight against climate change and the imperative of lowering greenhouse gas (GHG) emissions, as well as how critical it is to address poverty and social inequality by encouraging local economic growth and employment opportunities. This is evident in the sustainable value Ormat generates by employing a global diversified workforce that contributes to the social fabric of the communities in which we operate.

Ormat puts the earth and the energy needs of its people first. This is who we are; This is what we do. In 2019 Ormat published its first GRI level annual Sustainability Report (for the year 2018), the report covers the themes stipulated in the stakeholder materiality assessment and other company needs, primarily requests from stakeholders, while also answering best practice reporting practices and guidelines. The report, and processes included in it, has assisted in demonstrating Ormat's current considerable work in the field, and future additional work, to stakeholders. This process is ongoing and in years to come we will continue to improve and be able to report on more of our activities.

We continued our work with the local communities around our power plants, focusing on supporting education and health and other needs raised by the communities in our ongoing communication with them. The highlight of 2019 was the inauguration of the expansion of the school in Zunil. Ormat has been operating the Zunil power plant in Guatemala since 1999, and from the start had worked with the local indigenous community, supporting it in many avenues. The Zunil community outreach program is focused on the local school, as we believe supporting education is the best way to bring progress to the community. In 2019 the additional floor, which Ormat funded, of the local elementary school was inaugurated, adding junior high school classes.

Ormat's employees, their passion and relentless pursuit of excellence generates valuable energy from renewable sources, fueling economic, social and environmental progress and a stronger, more sustainable future for all. We are proud of the impact that our activities generate for communities and the planet and are committed to continuing our efforts to support meaningful and positive change in the world in 2020 and beyond.

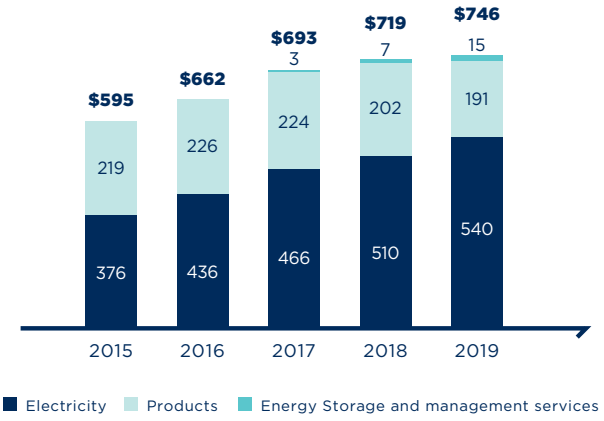
In summary, 2019 was another successful year and I am increasingly optimistic about Ormat's position and am certain that its best positioned to meet its long-term challenges. While I will be stepping away from the day-to-day management of Ormat, specially during this crisis and later on I will remain highly engaged, if I will be elected, as a member of the Board of Directors. Ormat maintains a deep and talented team. I truly believe that Doron, our new CFO Assaf Ginzburg and our strong management team, are the ideal team to lead Ormat into the future. Ormat remains an industry leader, the only vertically integrated participant in a fascinating industry.

Before I conclude this letter, I would like to personally thank all our stakeholders, and first and foremost our customers, shareholders, and employees as well as the Ormat management team

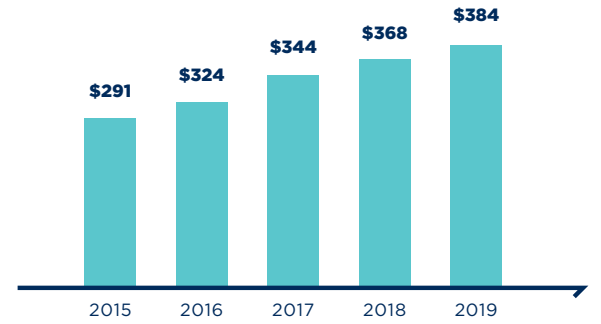
I believe that our long-term view in running Ormat will help us stand strong and steady crossing successfully the challenges that lies ahead of us, through and after the COVID 19 crisis.

Regards,
Isaac Angel
Chief Executive Officer

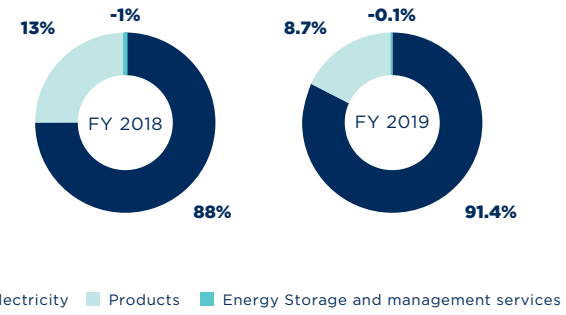
REVENUE GROWTH



ADJUSTED EBITDA*



INCREASING ADJUSTED EBITDA FROM ELECTRICITY SEGMENT TO SUPPORT PROFITABLE GROWTH*



***Note:** Our letter to shareholders contains forward looking statements and "non-GAAP financial measures" within the meaning of Regulation G under the Securities Exchange Act of 1934, as amended, including Adjusted EBITDA. Please see "Forward looking statements" in Ormat Technologies, Inc. 2019 Annual Report on Form 10-K under the "Cautionary Note Regarding Forward-Looking Statements" and the reconciliation of GAAP net income to EBITDA and Adjusted EBITDA under the Item 7 - "management's discussion and analysis of financial condition and results of operations".

UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-K

☑ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the fiscal year ended December 31, 2019

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)*
6140 Plumas Street, Reno, Nevada	**89519-6075**
(Address of principal executive offices)	*(Zip Code)*

(775) 356-9029
(Registrant's telephone number, including area code)

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

Title of Each Class	Trading Symbol(s)	Name of Each Exchange on Which Registered
Common Stock $0.001 Par Value	ORA	New York Stock Exchange

Securities Registered Pursuant to Section 12(g) of the Act:
None

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

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Exchange Act. Yes ☐ No ☑

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

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted 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 such files). Yes ☑ No ☐

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

Large accelerated filer ☑ Accelerated filer ☐ Non-accelerated filer ☐ Smaller reporting company ☐ Emerging growth company ☐

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

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

As of June 30, 2019, 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 $2,527,613,074 based on the closing price as reported on the New York Stock Exchange. Indicate the number of shares outstanding of each of the registrant's classes of common stock as of the latest practicable date: As of February 26, 2020, the number of outstanding shares of common stock, par value $0.001 per share was 51,031,652.

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, 2019.

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ORMAT TECHNOLOGIES, INC.

FORM 10-K FOR THE YEAR ENDED DECEMBER 31, 2019

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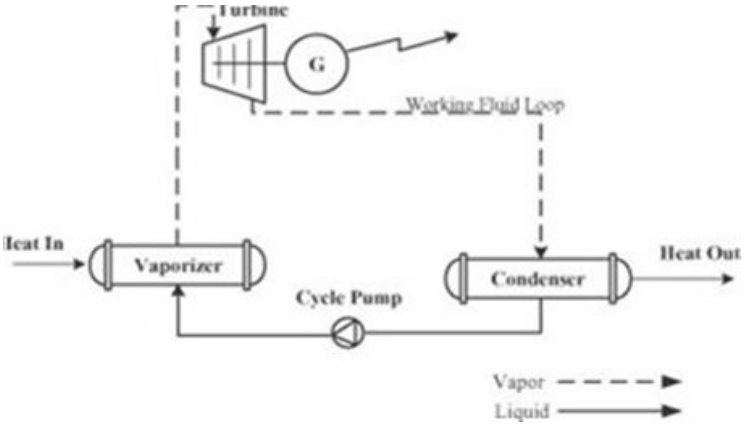
Glossary of Terms

Unless the context otherwise requires, all references in this annual report to "Ormat", "the Company", "we", "us", "our company", "Ormat Technologies", or "our" refer to Ormat Technologies, Inc. and its consolidated subsidiaries. A glossary of certain terms and abbreviations used in this annual report appears at the beginning of this report. When the following terms and abbreviations appear in the text of this report, they have the meanings indicated below:

Term	Definition
ACUA	Atlantic County Utilities Authority
Amatitlan Loan	$42,000,000 in initial aggregate principal amount borrowed by our subsidiary Ortitlan Limitada from Banco Industrial S.A. and Westrust Bank (International) Limited.
AMM	Administrador del Mercado Mayorista (administrator of the wholesale market — Guatemala)
ARRA	American Recovery and Reinvestment Act of 2009
Auxiliary Power	The power needed to operate a geothermal power plant's auxiliary equipment such as pumps and cooling towers
Availability	The ratio of the time a power plant is ready to be in service, or is in service, to the total time interval under consideration, expressed as a percentage, independent of fuel supply (heat or geothermal) or transmission accessibility
Balance of Plant equipment	Power plant equipment other than the generating units including items such as transformers, valves, interconnection equipment, cooling towers for water cooled power plants, etc.
BEAT	Base Erosion Anti-Abuse Tax
BESS	Battery Energy Storage Systems
BLM	Bureau of Land Management of the U.S. Department of the Interior
BOT	Build, operate and transfer
BSAAS	Battery Storage as a Service
Capacity	The maximum load that a power plant can carry under existing conditions, less auxiliary power
Capacity Factor	The ratio of the actual MWh generated and the generating capacity times 8760 hours expressed in percentage
CCA	Community Choice Aggregator
CDC	Caisse des Dépôts et Consignations, a French state-owned financial organization
CEO	Chief Executive Officer
CFO	Chief Financial Officer
C&I	Refers to the Commercial and Industrial sectors, excluding residential
CNEE	National Electric Energy Commission of Guatemala
COD	Commercial Operation Date
Company	Ormat Technologies, Inc., a Delaware corporation, and its consolidated subsidiaries
COSO	Committee of Sponsoring Organizations of the Treadway Commission
CPI	Consumer Price Index
CPUC	California Public Utilities Commission
DEG	Deutsche Investitions-und Entwicklungsgesellschaft mbH
DFIs	Development Finance Institutions
DOE	U.S. Department of Energy
DOGGR	California Division of Oil, Gas, and Geothermal Resources
DSCR	Debt Service Coverage Ratio
EBITDA	Earnings before interest, taxes, depreciation and amortization
EDF	Electricite de France S.A.
EGS	Enhanced Geothermal Systems
EIB	European Investment Bank
EMRA	Energy Market Regulatory Authority in Turkey

ENEE	Empresa Nacional de Energía Eléctrica
Enthalpy	The total energy content of a fluid; the heat plus the mechanical energy content of a fluid (such as a geothermal brine), which, for example, can be partially converted to mechanical energy in an Organic Rankine Cycle.
EPA	U.S. Environmental Protection Agency
EPC	Engineering, procurement and construction
EPS	Earnings per share
ERC	Kenyan Energy Regulatory Commission
ERCOT	Electric Reliability Council of Texas, Inc.
ERPA	Energy and Petroleum Regulatory Authority
Exchange Act	U.S. Securities Exchange Act of 1934, as amended
FASB	Financial Accounting Standards Board
FERC	U.S. Federal Energy Regulatory Commission
FIT	Feed-in Tariff
FPA	U.S. Federal Power Act, as amended
GAAP	Generally accepted accounting principles
GCCU	Geothermal Combined Cycle Unit
GDC	Geothermal Development Company
GEA	Geothermal Energy Association
Geothermal Power Plant	The power generation facility and the geothermal field
Geothermal Steam Act	U.S. Geothermal Steam Act of 1970, as amended
GHG	Greenhouse gas
GW	Giga watt
GWh	Giga watt hour
HELCO	Hawaii Electric Light Company
IDWR	Idaho Department of Water
IGA	International Geothermal Association
IID	Imperial Irrigation District
INDE	Instituto Nacional de Electrification
IOUs	Investor-Owned Utilities
IPPs	Independent Power Producers
IESO	The Independent Electricity System Operator (IESO) works at the heart of Ontario's power system.
IRS	Internal Revenue Service
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
JBIC	Japan Bank for International Cooperation
John Hancock	John Hancock Life Insurance Company (U.S.A.)
JOC	Joined operation contract
JPM	JPM Capital Corporation
KenGen	Kenya Electricity Generating Company Ltd.
Kenyan Energy Act	Kenyan Energy Act, 2006
KETRACO	Kenya Electricity Transmission Company Limited
KGRA	Known Geothermal Area
KLP	Kapoho Land Partnership
KPLC	Kenya Power and Lighting Co. Ltd.
kVa	Kilovolt-ampere
kW	Kilowatt - A unit of electrical power that is equal to 1,000 watts

kWh	Kilowatt hour(s), a measure of power produced
LADWP	Los Angeles Department of Water and Power
LCOE	Levelized Costs of Energy
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 energy produced
NBPL	Northern Border Pipe Line Company
NIS	New Israeli Shekel
NOC	Network Operations Center
NV Energy	NV Energy, Inc.
NYSE	New York Stock Exchange
NYISO	New York Independent System Operator, Inc.
OEC	Ormat Energy Converter
OFC	Ormat Funding Corp., a wholly owned subsidiary of the Company
OFC Senior Secured Notes	$190,000,000 8.25% Senior Secured Notes, due 2020 issued by OFC
OFC 2	OFC 2 LLC, a wholly owned subsidiary of the Company
OFC 2 Senior Secured Notes	Up to $350,000,000 Senior Secured Notes, due 2034 issued by OFC 2
Opal Geo	Opal Geo LLC
OPC	OPC LLC, a consolidated subsidiary of the Company
OPC Transaction	Financing transaction involving four of our Nevada power plants in which institutional equity investors purchased an interest in our special purpose subsidiary that owns such plants.
OPIC	Overseas Private Investment Corporation
OrCal	OrCal Geothermal Inc., a wholly owned subsidiary of the Company
OrCal Senior Secured Notes	$165,000,000 6.21% Senior Secured Notes, due 2020 issued by OrCal
ORC	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
ORIX	ORIX Corporation
ORPD	ORPD LLC, a holding company subsidiary of the Company in which Northleaf Geothermal Holdings, LLC holds a 36.75% equity interest
ORPD Transaction	Financing transaction involving the Puna complex and Don A. Campbell, OREG 1, OREG 2 and OREG 3 power plants in which Northleaf Geothermal Holdings, LLC purchased an equity interest in our special purpose subsidiary that owns such plants.
OrPower 4	OrPower 4 Inc., a wholly owned subsidiary of the Company
Ortitlan	Ortitlan Limitada, a wholly owned subsidiary of the Company
ORTP	ORTP, LLC, a consolidated subsidiary of the Company

ORTP Transaction	Financing transaction involving power plants in Nevada and California in which an institutional equity investor purchased an interest in our special purpose subsidiary that owns such plants.
Orzunil	Orzunil I de Electricidad, Limitada, a wholly owned subsidiary of the Company
PEC	Portfolio Energy Credits
PG&E	Pacific Gas and Electric Company
PGV	Puna Geothermal Venture, a wholly owned subsidiary of the Company
PJM	PJM Interconnection, L.L.C.
PLN	PT Perusahaan Listrik Negara
Power plant equipment	Interconnection equipment, cooling towers for water cooled power plant, etc., including the generating units
PPA	Power purchase agreement
ppm	Part per million
PTC	Production Tax Credit
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
RER	Renewable Energy Resource certificate
RPS	Renewable Portfolio Standards
RTO	Regional Transmission Organization
SaaS	Software as a Service
SCADA	Supervisory Control and Data Acquisition
SCPPA	Southern California Public Power Authority
SEC	U.S. Securities and Exchange Commission
Securities Act	U.S. Securities Act of 1933, as amended
SO#4	Standard Offer Contract No. 4
SOL	Sarulla Operations Ltd.
solar PV	solar photovoltaic
SOX Act	Sarbanes-Oxley Act of 2002
Southern California Edison	Southern California Edison Company
SPE(s)	Special purpose entity(ies)
SRAC	Short Run Avoided Costs
TASE	Tel Aviv Stock Exchange
Tax Act	Tax Cuts and Jobs Act
UIC	Underground Injection Control
Union Bank	Union Bank, N.A.
U.S.	United States of America
U.S. Treasury	U.S. Department of the Treasury
USG	U.S. Geothermal Inc.
VAT	Value Added Tax
VEI	Viridity Energy, Inc.
Viridity	Viridity Energy Solutions Inc., our wholly owned subsidiary
WHOH	Waste Heat Oil Heaters

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", "potential", or "contemplate" or the negative of these terms or other comparable terminology are intended to identify forward-looking statements, although not all forward-looking statements contain such words or expressions. The forward-looking statements in this annual report are primarily located in the material set forth under the headings Item 1 — "Business" contained in Part I of this annual report, Item 1A — "Risk Factors" contained in Part I of this annual report, Item 7 — "Management's Discussion and Analysis of Financial Condition and Results of Operations" contained in Part II of this annual report, and "Notes to Financial Statements" contained in Item 8 — "Financial Statements and Supplementary Data" contained in Part II of this annual report, but are found in other locations as well. These forward-looking statements generally relate to our plans, objectives and expectations for future operations and are based upon management's current estimates and projections of future results or trends. Although we believe that our plans and objectives reflected in or suggested by these forward-looking statements are reasonable, we may not achieve these plans or objectives. You should read this annual report completely and with the understanding that actual future results and developments may be materially different from what we expect attributable to a number of risks and uncertainties, many of which are beyond our control.

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

- significant considerations, risks and uncertainties discussed in this annual report;
- geothermal resource risk (such as the heat content, useful life and geological formation of the reservoir);
- operating risks, including equipment failures and the amounts and timing of revenues and expenses;
- financial market conditions and the results of financing efforts;
- weather and other natural phenomena including earthquakes, volcanic eruption, drought and other natural disasters;
- political, legal, regulatory, governmental, administrative and economic conditions and developments in the United States, and other countries in which we operate and, in particular, possible import tariffs, possible late payments, the impact of recent and future federal, state and local regulatory proceedings and changes, including legislative and regulatory initiatives regarding deregulation and restructuring of the electric utility industry, public policies and government incentives that support renewable energy and enhance the economic feasibility of our projects at the federal and state level in the United States, and elsewhere, and carbon-related legislation;

- risks and uncertainty with respect to our internal control over financial reporting, including identification of a material weakness which, if not timely remediated, may adversely affect the accuracy and reliability of our financial statements;

- the impact of fluctuations in oil and natural gas prices under certain of our PPAs;

- the competition with other renewable sources or a combination of renewable sources on the energy price component under future PPAs;

- risks and uncertainties with respect to our ability to implement strategic goals or initiatives in segments of the clean energy industry or new or additional geographic focus areas;

- risk and uncertainties associated with our operating storage facilities and with future development of storage and geothermal projects which operate as "merchant" facilities without long-term sales agreements, including the variability of revenues and profitability of such projects;

- 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;

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

- contract counterparty risk, including late payments or no payments;

- 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;

- our ability to access the public markets for debt or equity capital quickly;

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

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

- when, if and to what extent opportunities under our commercial cooperation agreement with ORIX Corporation may in fact materialize;

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

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

- development and construction of solar PV and energy storage projects, if any, may not materialize as planned;

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

- the impact of the corona virus outbreak emanating from China and its impact on our ability to operate and supply raw materials and products and on our ability to travel globally to serve our customer and construct our own power plants.

Company Contact and Sources of Information

Our website is www.ormat.com. Information contained on our website is not part of this Report. Information that we furnish or file with the SEC, including our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and any amendments to, or exhibits included in, these reports are available for download, free of charge, through our website. Our SEC filings, including exhibits filed therewith, are also available directly on the SEC's website at www.sec.gov.

You may request a copy of our SEC filings at no cost to you, by writing to the Company address appearing on the cover page of this annual report or by calling us at (775) 356-9029.

PART I

ITEM 1. BUSINESS

Overview

We are a leading vertically integrated company that is primarily engaged in the geothermal, and recovered energy power businesses. We are also expanding into the solar Photovoltaic (PV) and energy storage and management services business.

We design, develop, build, sell, own, and operate clean, environmentally friendly geothermal and recovered energy-based power plants, usually using equipment that we design and manufacture. Our objective is to become a leading global provider of renewable energy and we have adopted a strategic plan to focus on several key initiatives to expand our business.

We currently conduct our business activities in three business segments:

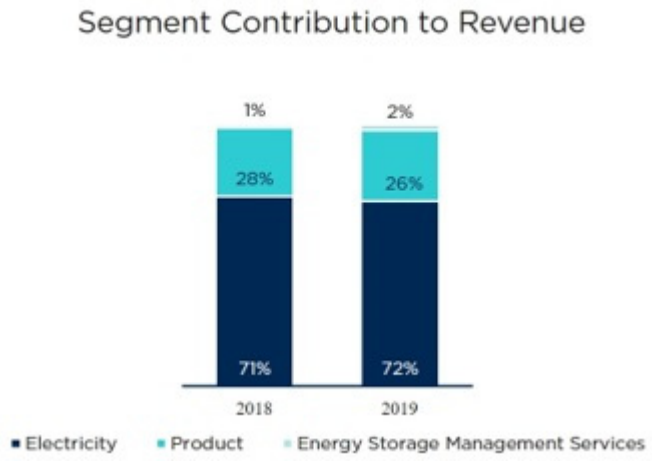
- *Electricity Segment.* In the Electricity segment, which contributed 72.4% of our total revenues in 2019, we develop, build, own and operate geothermal, solar PV and recovered energy-based power plants in the United States and geothermal power plants in other countries around the world and sell the electricity they generate. In 2019, we derived 61.8% of our Electricity segment revenues from our operations in the U.S. and 38.2% from the rest of the world.

- *Product Segment.* In the Product segment, which contributed 25.6% of our total revenues, we design, manufacture and sell equipment for geothermal and recovered energy-based electricity generation and remote power units and provide services relating to the engineering, procurement and construction of geothermal and recovered energy-based power plants. In 2019, we derived 16.0% of our Product segment revenues from our operations in the United States and 84.0% from the rest of the world.

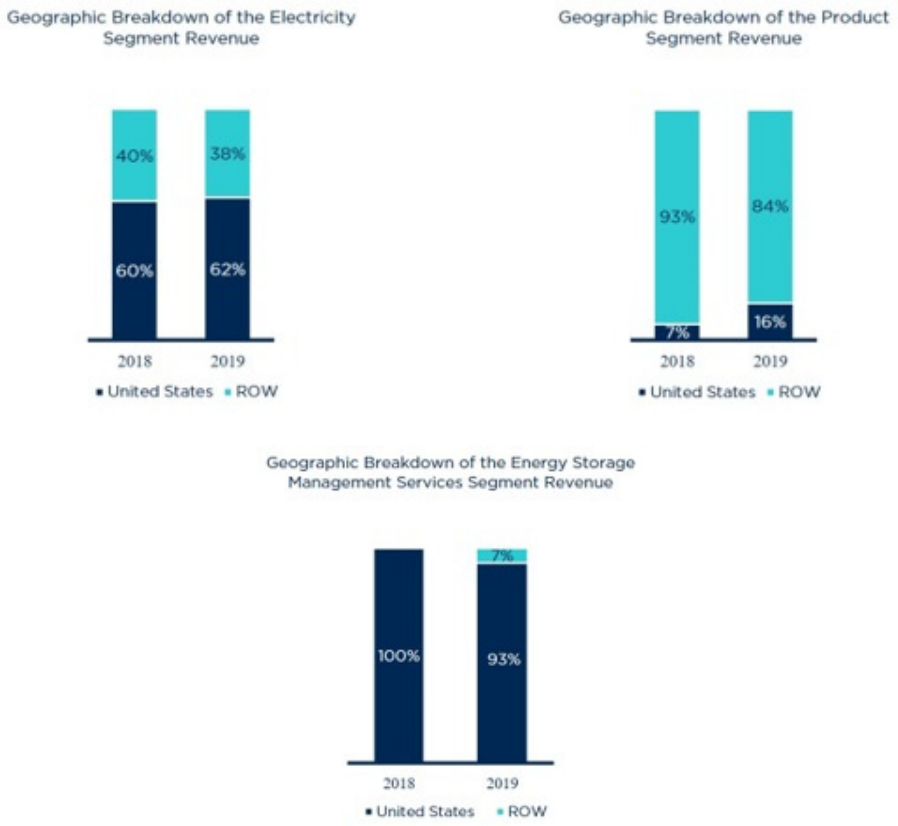
- *Energy Storage and Management Services Segment.* In the new Energy Storage and Management Services segment, which contributed 2.0% of our total revenues, we provide energy storage, demand response and energy management related services as well as services relating to the engineering, procurement, construction, operation and maintenance of energy storage units mainly through our Viridity business. In 2019, we derived 92.5% of our Energy Storage and Management Services segment from our operations in the United States.

The charts below show the relative contributions of each of our segments to our consolidated revenues and the geographical breakdown of our segment revenues for the fiscal year ended December 31, 2019.

The following chart sets forth a breakdown of our revenues for each of the years ended December 31, 2018 and 2019:



The following chart sets forth the geographical breakdown of revenues attributable to our Electricity, Product and Energy Storage and Management Services segments for each of the years ended December 31, 2018 and 2019:



Technology and products we use in our operations include geothermal, recovered energy, solar PV and energy storage:

Our owned geothermal power plants include both power plants that we have built and power plants that we have acquired. The substantial majority of the power plants that we currently own or operate produce electricity from geothermal energy sources. Geothermal energy is a clean, renewable and generally sustainable form of energy derived from the natural heat of the earth. Unlike electricity produced by burning fossil fuels, electricity produced from geothermal energy sources is produced without emissions of certain pollutants such as nitrogen oxide, and with far lower emissions of other pollutants such as carbon dioxide. As a result, electricity produced from geothermal energy sources contributes significantly less to global warming and local and regional incidences of acid rain than energy produced by burning fossil fuels. In addition, compared to power plants that utilize other renewable energy sources, such as wind or solar, geothermal power plants are generally available all year-long and all day-long and can therefore provide base-load electricity services. Geothermal power plants can also be custom built to provide a range of electricity services such as baseload, voltage regulation, reserve and flexible capacity. Geothermal energy is also an attractive alternative to other sources of energy, support of a diversification strategy to avoid dependence on any one energy source or politically sensitive supply sources. We recently launched our first geothermal and solar PV hybrid project, in which the electricity generated from a solar PV power plant is used to offset the equipment's energy use at the geothermal facility, thus increasing the renewable energy delivered by the project to the grid.

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

In 2017, we entered the energy storage, demand response and energy management markets. We plan to accelerate long-term growth, expand our market presence in a growing market and further develop our energy storage and management services, including the VPower™ software platform.

Our Power Generation Business (Electricity Segment)

Each of our current geothermal power plants sells substantially all of its output pursuant to long-term, fixed price PPAs to various counterparties denominated in US dollars or Euros. These contracts had a total weighted average remaining term, based on contributions to segment revenue, of approximately 17 years at December 31, 2019. In addition, the counterparties to our PPAs in the United States had a credit rating of between Aa2 to Baa2. The purchasers of electricity from our foreign power plants are mainly state-owned entities in countries with below investment grade rating.

Power Plants in Operation

We own and operate 25 geothermal, REG and solar sites globally with an aggregate generating capacity of 914 MW. Geothermal comprises 93% of our generating capacity. In 2019, our geothermal and REG power plants generated at a capacity factor of 87% and 74%, respectively, which is higher than typical capacity factors for wind and solar producers that are usually at 20% to 30%.

The table below summarizes certain key non-financial information relating to our power plants and complexes as of February 25, 2020. The generating capacity of certain of our power plants and complexes listed below has been updated from our 2018 disclosure to reflect changes in the resource temperature and other factors that impact resource capabilities:

Type	Region	Plant	Ownership[1]	Generating capacity (MW)[2]	PPA Tenor	Capacity Factor
Geothermal	California	Ormesa Complex	100%	39	23	
		Heber Complex	100%	81	14	
		Mammoth Complex	100%	29	13	72%
		Brawley	100%	13	12	
	West Nevada	Steamboat Complex	100%	65	18	88%
		Brady Complex	100%	26	16	
	East Nevada	Tuscarora	100%	18	13	
		Jersey Valley	100%	10	13	
		McGinness Hills	100%	143	19	93%
		Don A. Campbell	63.3%	36	16	
		Tungsten Mountain[4]	100%	27	24	
	North West Region	Neal Hot Springs	60%	22[6]	19	
		Raft River	100%	11	13	92%
		San Emidio	100%	11	19	
	Hawaii	Puna	63.3%	38	33	NA%[7]
	International	Amatitlan (Guatemala)	100%	20	9	
		Zunil (Guatemala)	97%	20[10]	15	
		Olkaria III Complex (Kenya)	100%	150	15	88%
		Bouillante (Guadeloupe Island, France)	63.75%[3]	15	11	
		Platanares (Honduras)	100%	38	13	
Total Consolidated Geothermal				812		87%[8]
REG		OREG 1	63.3%	22	12	
		OREG 2	63.3%	22	15	
		OREG 3	63.3%	5.5	10	
		OREG 4	100%	3.5[5]	10	
Total REG				53		74%
solar		Tungsten Mountain	100%	7[9]	24	
Total solar				7		
Unconsolidated Geothermal	Indonesia	Sarulla Complex	12.75%	42	28	
Total Unconsolidated Geothermal				42		
Total				**914**		

1. We indirectly own and operate all of our power plants, although financial institutions hold equity interests in three of our subsidiaries: (i) Opal Geo subsidiaries, which own the McGinness Hills Phases 1 and 2 geothermal power plants, the Tuscarora and Jersey Valley power plants and the second phase of the Don A. Campbell power plant, all located in Nevada; (ii) ORNI 41, which owns the McGinness Hills Phase 3 located in Nevada; and (iii) ORNI 47, which owns the Tungsten Mountain geothermal power plant located in Nevada. In the table above, we list these power plants as being 100% owned because all of the generating capacity is owned by these subsidiaries and we control the operation of the power plants. The nature of the equity interests held by the financial institution is described below in Item 7 — "Management's Discussion and Analysis of Financial Condition and Results of Operations" under the headings "Opal Transaction", "McGinness Hills 3 Tax Monetization Transaction" and "Tungsten Mountain Tax Monetization Transaction.

   Notwithstanding our 63.75% equity interest in the Bouillante power plant, 60% equity interest in the Neal Hot Spring power plant and 63.25% direct equity interest in the Puna plant, the first phase of Don A. Campbell, OREG 1, OREG 2 and OREG 3 power plants as well as the indirect interest in the second phase of the Don A. Campbell complex owned by our subsidiary, ORPD, we list 100% of the generating capacity of the Bouillante power plant, the Neal Hot Springs power plant and the power plants in the ORPD portfolio in the table above because we control their operations. We list our 12.75% share of the generating capacity of the Sarulla complex as we own a 12.75% minority interest. Revenues from the Sarulla complex are not consolidated and are presented under "Equity in earnings (losses) of investees, net" in our financial statements.

2. References to generating capacity generally refer to gross generating capacity less auxiliary power. We determine the generating capacity of these power plants by taking into account resource and power plant capabilities. 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 geothermal resource, and operational issues affecting performance during that year.

3. We own 63.75%, CDC owns 21.25% and Sageos own 15.0% of the Bouillante power plant.

4. Tungsten Mountain is a Hybrid Geothermal and solar power plant that uses the solar energy for geothermal power plant auxiliary power. The solar power plant generates 7 MW and is presented separately in the table above.

5. The OREG 4 power plant is not operating at full capacity due to low run time of the compressor station that serves as the power plant's heat source. This has resulted in lower power generation.

6. We own 60% and Enbridge owns 40% of the Neal Hot Springs power plant.

7. The Puna geothermal power plant has been shut down since May 3, 2018 when the Kilauea volcano located in close proximity to it erupted following a significant increase in seismic activity in the area. We continue efforts to resume its operation and we signed an amended PPA to extend its duration and expand its contract capacity as described below in Item 7 — "Management's Discussion and Analysis of Financial Condition and Results of Operations" under the headings "Recent Development". In addition, we

8. The total availability of the geothermal power plants excludes the Puna power plant that is not in operation as discussed above.

9. Tungsten Mountain includes the 7AC MW Tungsten solar power plant that commenced commercial operation in July 2019.

10. In Zunil power plant revenues used to be calculated based on 24 MW generating capacity and was unrelated to the performance of the reservoir. In 2019 and onward, revenues are calculated based on the actual generation of the power plant, therefore the generating capacity was updated to reflect the current generating capacity.

New Power Plants

We are currently in various stages of construction of new power plants and expansion of existing power plants. Our construction and expansion plan include between 90 MW and 95 MW in generating capacity from geothermal and solar PV power plants in the United States. In addition, we have several geothermal and solar PV projects in the United States, Kenya and Guadeloupe that are either under initial stages of construction or under different stages of development with an aggregate capacity of between 71 MW and 76 MW.

We have substantial land positions across 31 prospects in the United States, and 10 prospects in Ethiopia, Guatemala, Honduras, Indonesia and New Zealand that we expect will support future geothermal development and on which we have started or plan to start exploration activity. These land positions are comprised of various leases, exploration concessions for geothermal resources and an option to enter into leases.

Our Product Business (Product Segment)

We design, manufacture and sell products for electricity generation and provide the related services described below. We primarily manufacture products to fill customer orders, but in some situations, we manufacture products as inventory for future projects that we will own and for future third party projects.

Power Units for Geothermal Power Plants

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

Power Units for Recovered Energy-Based Power Generation

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

EPC of Power Plants

We serve as an EPC contractor for geothermal and recovered energy power plants on a turnkey basis, using power units we design and manufacture. Our customers are geothermal power plant owners as well as our target customers for the sale of our recovered energy-based power units as described above. Unlike many other companies that provide EPC services, we believe that our competitive advantage is in using equipment that we manufacture allowing us better quality and 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 capacities ranging from 200 watts to 5,000 watts, which operate unattended in extreme hot or cold climate conditions. Our customers include contractors who install gas pipelines in remote areas and offshore platform operators and contractors. In addition, we design, manufacture, and sell generators, including heavy duty direct-current generators, for various other uses.

Our Energy Storage and Management Services Segment

Our storage business currently manages, through the Viridity platform, curtailable customer loads across multiple sites under contracts with leading U.S. retail energy providers and directly with large C&I customers, including management of a portfolio of non-utility storage assets located in the northeastern United States . We serve our own energy storage assets and distributed customers through a NOC, which is operated 24/7 using our VPower^{TM} software platform and a SCADA platform.

VPower™ services are provided to customers using a SaaS model under which we receive license fees and/or a portion of the revenue and savings that are achieved for our customers.

We expect that the ecosystem we created, combining our Viridity's capabilities and legacy Ormat capabilities, including among other things, our global presence, experience in technology and system integration, development and EPC of power generation projects, flexible business models, and our reputation and experience in the geothermal and recovered energy sectors, will enable us to expand in the growing energy storage sector.

Our Viridity business obtained and maintains authorization from FERC to make wholesale purchase and sales of energy, capacity, and ancillary services at market-based rates, and we have confirmed membership status with eligibility to serve designated contractual functions within each of the following ISOs and RTOs: PJM, NYISO, ERCOT, MISO and ISONE. In the future, we may need to obtain and maintain similar membership and eligibility status with other ISO and RTO markets in which our Viridity business will operate, such as CAISO.

In 2019, we successfully brought on line two new Ormat/Viridity-owned BESS projects: 20MW/20 MWh in Alpha, NJ and 2 MW / 5 MWh in Hinesburg, Vermont. The Hinesburg project operates under an energy storage services agreement with the Vermont Electric Co-operative, under which we provide 1 MW of peak load reduction services several times a year. During the rest of the time, the Hinesburg project provides ancillary services to ISONE, thereby generating additional revenues.

We are currently in the commissioning stage of a project in Georgetown, Texas and developing a new project in California and a pilot system in Israel. We have a substantial pipeline for future development in the United States that and we expect to commission between 150 MW and 200 MW between 2020 and 2022. We plan to continue leveraging our worldwide experience in project development and finance, as well as our relationships with utilities and other market participants, to develop additional such BESS projects.

History

Ormat Technologies, Inc. was formed as a Delaware corporation in 1994 by our former parent company Ormat Industries. Ormat Industries was one of the first companies to focus on the development of equipment for the production of clean, renewable and generally sustainable forms of energy. On February 12, 2015, we successfully completed the acquisition of Ormat Industries in an all-stock merger, eliminating its majority ownership and control of Ormat Technologies.

Business Strategy

Our strategy is focused on further developing a geographically balanced portfolio of geothermal, solar (PV) and recovered energy assets and continuing our leading position in the geothermal energy market with the objective of becoming a leading global provider of renewable energy. Our strategy focuses on three main elements:

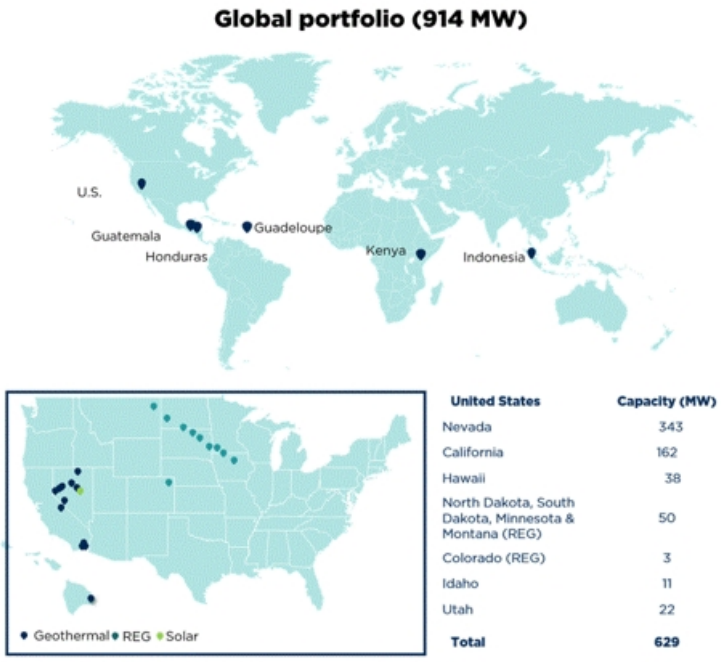
- our core geothermal business in the United States as well as globally;
- establishing a strong market position in the energy storage market; and
- exploring opportunities in new areas by looking for synergistic growth opportunities utilizing our core competence, market reputation as a successful company and new market opportunities focused upon environmental solutions.

We intend to implement this strategy through:

- *Using Our Operational Capabilities to Increase Output from our Existing Geothermal Power Plants — i*ncreasing 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.
- *Creating Cost Savings through Increased Operating Efficiency* — increasing efficiencies in our operating power plants and manufacturing facility including procurement by adding new technologies, restructuring of management control, automating part of our manufacturing work and centralizing our operating power plants.
- *Diversifying our Customer Base* — evaluating a number of strategies for expanding our customer base to the CCA and C&I markets. In the near term, however, we expect that substantial majority of our revenues will continue to be generated from our traditional electrical utility customer base for the Electricity segment.

- *Maintaining a Prudent and Flexible Capital Structure* — we have various financing structures in place, including non-recourse project financings, the sale of differential membership interests and equity interests in certain subsidiaries, as well as revolving credit facilities and term loans. We believe our cash flow profile, the long-term nature of our contracts, and our ability to raise capital provide greater flexibility for optimizing our capital structure.
- *Improving our Technological Capabilities* — 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 expanding our core geothermal competencies to provide high efficiency solutions for high enthalpy applications by utilizing our binary enhanced cycle and technology.
- *Development and Construction of New Geothermal Power Plants* — continuously seeking out commercially exploitable geothermal resources, developing and constructing new geothermal power plants by either entering into long-term PPAs providing stable cash flows or selling in the "merchant" market in jurisdictions where the regulatory, tax and business environments encourage or provide incentives for such development;
- *Expanding our Geographical Reach* — increasing our business development activities in an effort to grow our business in the global markets in all business segments. While we continue to evaluate global opportunities, we currently see the U.S., Kenya, Indonesia, and Ethiopia as attractive markets for our Electricity segment and New Zealand, Philippines, Turkey, Chile, Indonesia and China as attractive markets for our Product segment. We are actively looking at ways to expand our presence in those countries.
- *Acquisition of New Assets* — expanding and accelerating growth through acquisition activities globally, aiming to acquire additional geothermal assets with long term PPAs or without a PPA as well as operating and development assets that can support our storage business.
- *Manufacturing and Providing Products and EPC Services Related to Renewable Energy* — designing, manufacturing and contracting power plants for our own use and selling to third parties power units and other generation equipment for geothermal and recovered energy-based electricity generation;
- *Expanding into New Technologies* - leveraging our technological capabilities over a variety of renewable energy platforms, including solar power generation and energy storage. We may acquire companies with integration and technological capabilities that we do not currently have, or develop new technology ourselves, where we can effectively leverage our expertise to implement this part of our strategic plan.

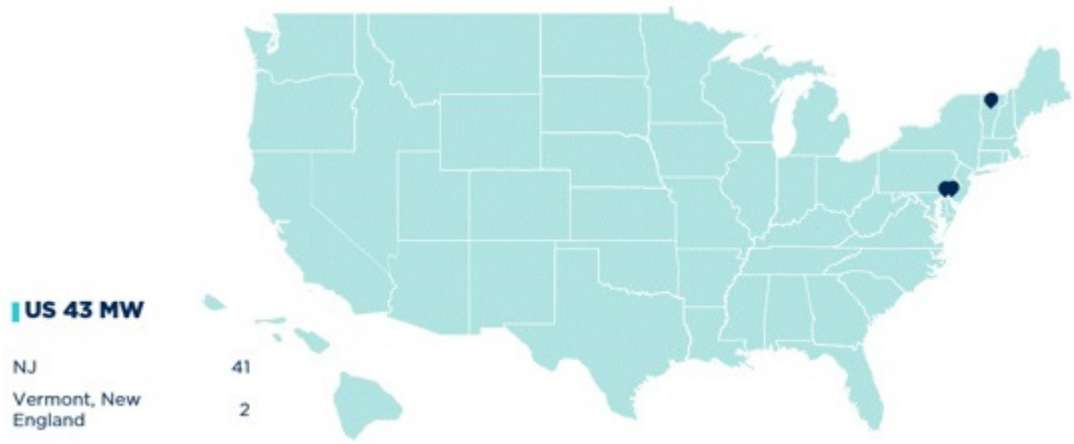
The map below shows our worldwide portfolio of operating geothermal, solar PV and recovered energy power plants as of February 25, 2020.



United States	Capacity (MW)
Nevada	343
California	162
Hawaii	38
North Dakota, South Dakota, Minnesota & Montana (REG)	50
Colorado (REG)	3
Idaho	11
Utah	22
Total	**629**

* In the Sarulla complex, we include our 12.75% share only.

The map below shows our portfolio of operating storage facilities as of February 25, 2020.



Industry Background

Geothermal Energy

There are several different sources or methods of obtaining geothermal energy, which are described below.

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

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

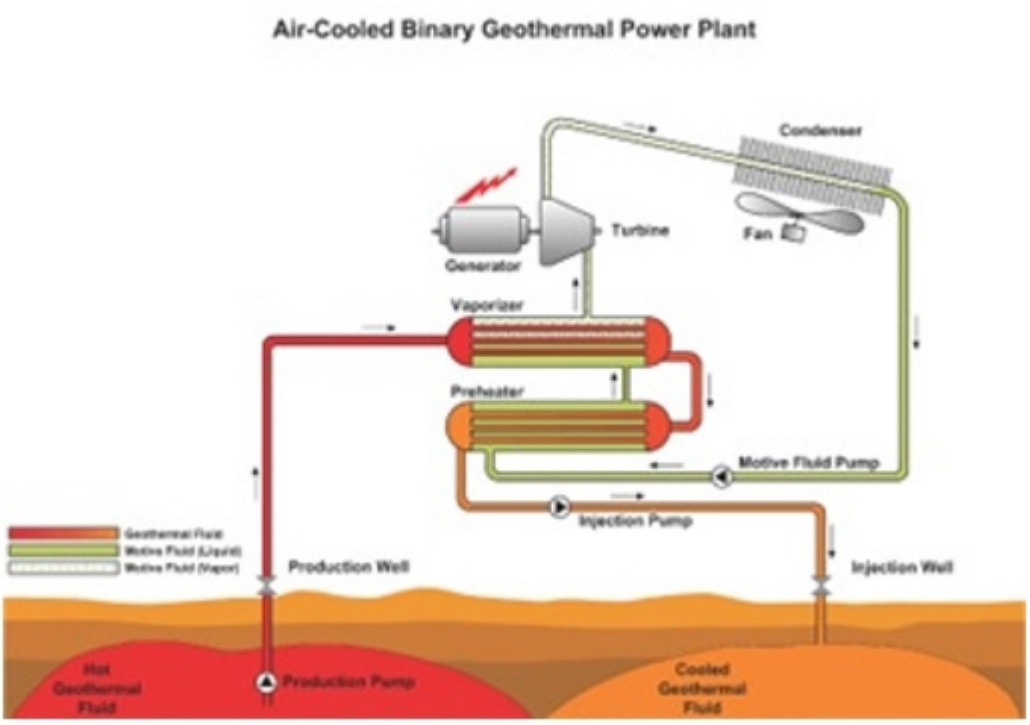
Co-produced geothermal from oil and gas fields, geo-pressurized resources — Another source of geothermal energy is hot water produced as a by-product of oil and gas extraction. When oil and gas wells are deep, the extracted fluids are often at high temperatures and if the water volume associated with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

Geothermal Power Plant Technologies

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

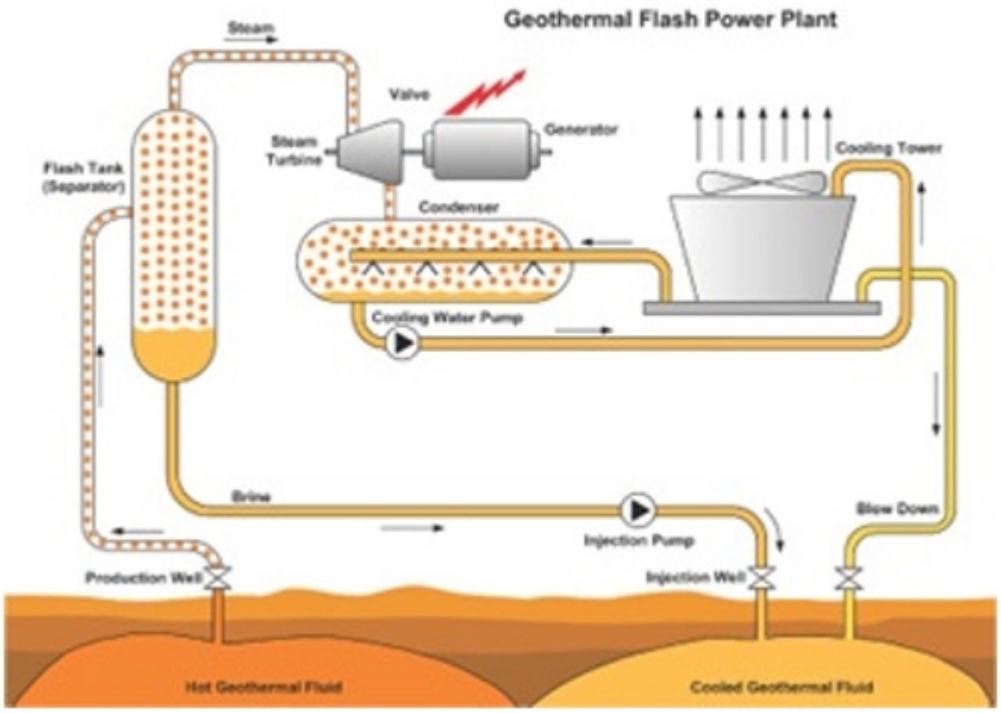
Binary System

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



Flash Design System

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

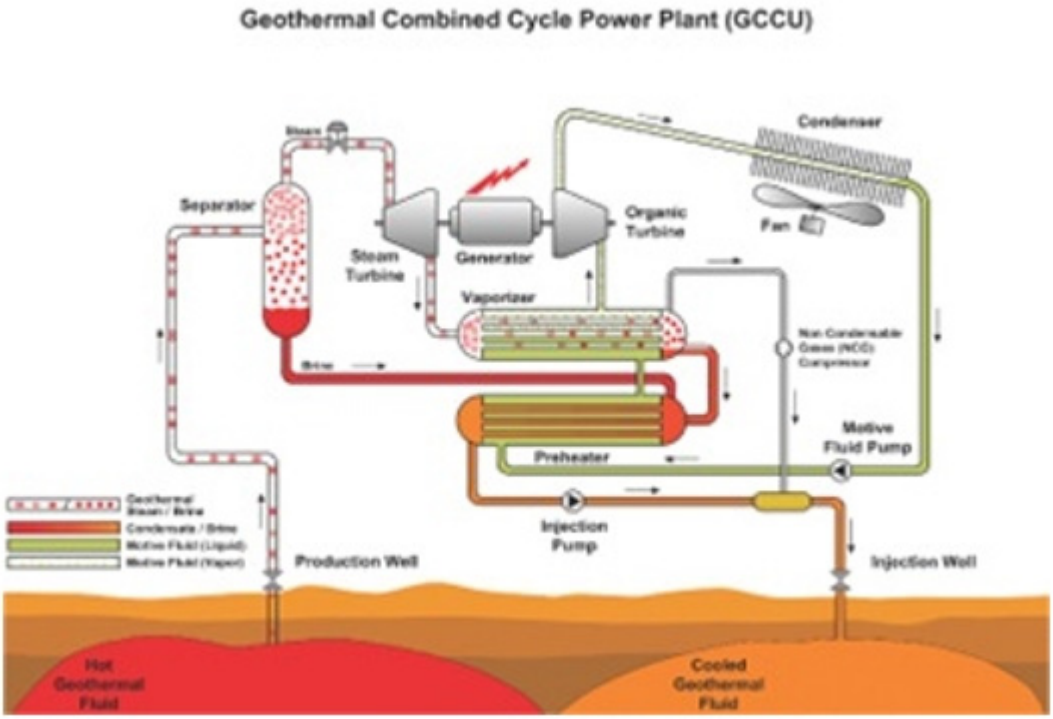


In some instances, the wells directly produce dry steam and the steam is fed directly to the steam turbine with the rest of the system similar to the flash technology described above.

Our Proprietary Technology

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

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

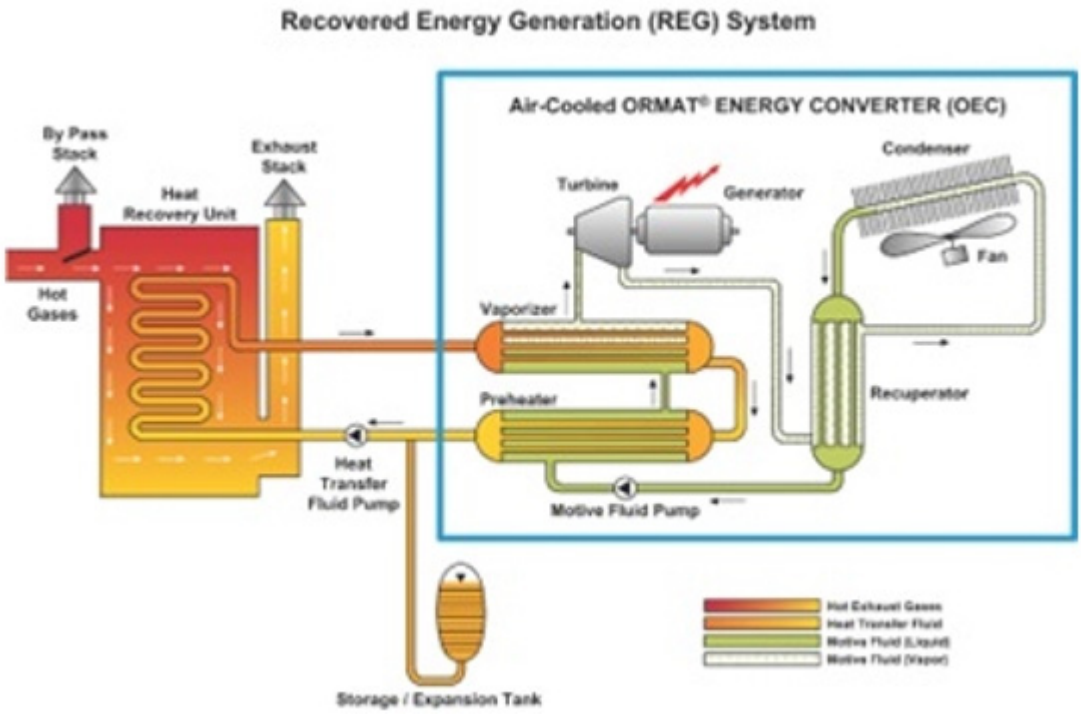


In the conversion of geothermal energy into electricity, our technology has a number of advantages over conventional geothermal steam turbine plants. A conventional geothermal steam turbine plant consumes significant quantities of water, causing depletion of the aquifer and requiring cooling water treatment with chemicals and consequently a need for the disposal of such chemicals. A conventional geothermal steam turbine plant also creates a significant visual impact in the form of an emitted plume from the cooling towers, especially during cold weather. By contrast, our binary and combined cycle geothermal power plants have a low profile with minimal 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 maintenance and higher yearly availability. For instance, the OEC employs a low speed and high efficiency organic vapor turbine directly coupled to the generator, eliminating the need for reduction gear. In addition, with our binary design, there is no contact between the turbine blade and geothermal fluids, which can often be very erosive and corrosive. Instead, the geothermal fluids pass through a heat exchanger, which is less susceptible to erosion and can adapt much better to corrosive fluids. In addition, with the organic vapor condensed above atmospheric pressure, no vacuum system is required.

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

Our REG technology is depicted in the diagram below.



Patents

As of February 25, 2020, we have 63 issued U.S. patents and four pending U.S. patents applications. These patents and patent applications cover our products (mainly power units based on the ORC) and systems (mainly geothermal power plants and industrial waste heat recovery plants for electricity production). The product-related patents cover components that include turbines, heat exchangers, air coolers, seals and controls as well as control of operation of geothermal production well pumps. The system-related patents cover not only particular components but as well as the overall energy conversion system from the "fuel supply" (e.g., geothermal fluid, waste heat, biomass or solar) to electricity production.

The system-related patents also cover subjects such as waste heat recovery related to gas pipeline compressors and industrial waste heat, solar power systems, disposal of non-condensable gases present in geothermal fluids, reinjection of other geothermal fluids ensuring geothermal resource sustainability, power plants for very high-pressure geothermal resources, two-phase fluids, low temperature geothermal brine as well as processes related to EGS. 55 of our patents cover combined cycle geothermal power plants, in which the steam first produces power in a backpressure steam turbine and is subsequently condensed in a vaporizer of a binary plant, which produces additional power. The remaining terms of our issued patents range from one year to 16 years. The loss of any single patent would not have a material effect on our business or results of operations.

Research and Development

We conduct research and development activities intended to improve plant performance, reduce costs, and increase the breadth of our product offerings. The primary focus of our research and development efforts is targeting power plant conceptual thermodynamic cycle and major equipment including continued performance, cost and land usage improvements to our condensing equipment, and development of new higher efficiency and higher power output turbines. New realms for innovation include implementation of predictive maintenance software and automation of power plants performance analysis. Based on vast experience and strong engineering and manufacturing assets, products for new markets are in early development stages within the R&D effort.

Our Viridity business continues to develop new optimization algorithms to optimize the life of a battery energy storage system (BESS), to optimize our and our customers' economic return and to forecast the trends surrounding our customers' electricity consumption and the electric grid including times of peak demands and the usage of ancillary services.

We have also focused our development efforts on the engineering and design of improved energy storage systems. These development efforts include, among others, building of an energy storage lab for testing of various batteries, inverters

and the integration of both. Further efforts include the development of the control hardware and software for energy storage systems to follow electric grid and market signals and to optimize their delivery of energy into the markets .

We have developed, and continue to develop, system integration capabilities that match the appropriate system and system sizing with the appropriate battery chemistry, electrical and physical components to accommodate our needs or needs of the customers that will own such energy storage systems in light of the markets in which they will operate. We are searching for alternative chemistries, products and combinations of hybrid solutions to best address our energy storage product customers' needs.

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

Market Opportunities

Geothermal Market Opportunities

Renewable energy in general provides a sustainable alternative to the existing solutions to two major global issues: climate change and diminishing fossil fuel reserves. Renewable energy is sustainable, clean and decarbonizes the grid. These environmental benefits have led major countries to focus their efforts on the development of renewable energy sources in general and geothermal specifically.

Based on an announcement by the IGA in January 2020, geothermal power is generated in 29 countries with a total installed power generation capacity of 15,400 MW at the end of 2019. The leading countries are the U.S., Indonesia, Philippines, Turkey, Mexico and New Zealand. The IGA expects that 4,500 MW will be added by 2025.

Having realized the importance of renewable energy including geothermal alternatives, various governments have been preparing regulatory frameworks and policies, and providing incentives to develop the sector.

United States

Interest in geothermal energy in the United States remains strong for numerous reasons, including legislative support, RPS goals (as described below), coal, natural gas and nuclear power plant retirements, and an increasing awareness of the positive value of geothermal characteristics when compared to intermittent renewable technologies.

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

Geothermal energy provides numerous benefits to the U.S. grid and economy. Geothermal development and operation bring economic benefits in the form of taxes and long term high-paying jobs, and it currently has one of the lowest LCOE of all power sources in the United States, according to the U.S. Energy Information Administration's report published in February 2019. Additionally, improvements in geothermal production make it possible to provide ancillary and on-demand services. This helps load serving entities avoid additional costs from purchasing and then balancing intermittent resources with storage or new transmission.

State level legislation

Many state governments have enacted an RPS program under which utilities are required to include renewable energy sources as part of their energy generation. Under an RPS, participating states have set targets for the production of their energy from renewable sources by specified dates. Renewable energy generation under RPS programs are tracked through the production of Renewable Energy Credits (RECs). Load serving entities track the RECs to ensure they are meeting the mandate prescribed by the RPS.

Currently in the United States, 42 states plus the District of Colombia and four territories have enacted an RPS, renewable portfolio goals, or similar laws (such as clean energy standards or goals) requiring or encouraging load serving entities in such states to generate or buy a certain percentage of their electricity from renewable energy or recovered heat sources. The vast majority of Ormat's geothermal projects can be found in California, Nevada, and Hawaii which have some of the most stringent RPS programs in the country.

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

Below are RPS targets in the states in which we are operating:

State	RPS Target	Year	Remarks
California.....	60%	2030	RPS targets set for future years: 44% – 2024, 52% – 2027, and 60% – 2030. 100% zero carbon by 2045.
Nevada.....	50%	2030	RPS target of 50% by 2030 and 100% zero carbon by 2050. The state has a credit multiplier for photovoltaic and on peak energy savings.
Hawaii	100%	2045	RPS targets set for future years: 30% by 2020, 40% by 2030, and 70% by 2040
Oregon.....	25%	2025	Increased RPS of 50% by 2040 applies to IOUs who have a share of more than 3% of the state's load; for utilities with a load-share of 1.5% – 3%, requirement is 10% in 2025, and for utilities with a load share of less than 1.5%, it is 5% in 2025

States also provide incentives to geothermal energy producers. Nevada provides a property tax abatement of up to 55% for real and tangible personal property used to generate electricity from geothermal sources. The abatement may extend up to twenty years if certain job creation requirements are met. The California Energy Commission provides favorable grants and loans to promote the development of new or existing geothermal resources and technologies within the state. In Idaho, geothermal energy producers are exempt from property tax and, in lieu, pay a tax of 3% of gross energy earnings.

Global

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

Operations outside of the United States may be subject to and/or benefit from increasing efforts by governments and businesses around the world to fight climate change and move towards a low carbon, resilient and sustainable future. According to a recent report by the International Renewable Energy Agency entitled Toward 100% Renewable Energy, in 2019, a total of 61 countries had set a 100% renewable energy target in at least one end-use sector, up from 60 countries in 2018.

We believe that several global initiatives will create business opportunities and support global growth of the renewable sector such as the historic agreement at the COP21 UN Climate Change Conference held in Paris, which, for the first time, created a commitment by 127 parties to setting nationally determined climate targets and reporting on their progress. Following this agreement, the EIB and other multilateral institutions have committed to provide $100 billion of new financing for climate action projects over the next five years to assist countries in reaching their targets. However, on June 1, 2017, President Donald J. Trump announced that the United States will withdraw from this agreement.

In addition, in 2015, a group of 20 countries, including the United States, United Kingdom, France, China and India, pledged to double their respective budgets for renewable energy technology over five years as part of a separate initiative called Mission Innovation. At the same time, the Breakthrough Energy Coalition was launched by a group of 28 private investors with the objective of bringing companies with the potential to deliver affordable, reliable and carbon free power from the research lab to the market.

We believe that as a general matter these developments and governmental plans will create growth and expansion opportunities for us internationally.

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 encouraging new capacity development and/or refurbishment of existing assets by independent power developers. These foreign governments have taken a variety of approaches to encourage the development of competitive power markets, including awarding long-term contracts for energy and capacity to independent power generators and creating competitive wholesale markets for selling and trading energy, capacity, and related products. Some foreign regions and countries have also adopted active government programs designed to encourage clean renewable energy power generation such as the following countries in which we operate, sell products and/or are conducting business development activities:

Europe

Europe has the fourth largest geothermal power capacity, the majority of which stems from Italy and Turkey. A significant part of our European operations is in Turkey. We are looking for opportunities to expand in Europe, particularly in Germany.

Turkey

Until recently, Turkey was the fastest growing geothermal market worldwide with the theoretical potential for 31 GW of geothermal capacity and with a proven geothermal capacity of 4.5 GW, according to the Turkish Mineral Technical Exploration Agency. Due to the economic situation in Turkey, there has been a slowdown.

Since 2004, we have established strong business relationships in the Turkish market and provided our range of solutions including our binary systems, to over 40 geothermal power plants with a total capacity of approximately 900 MW, of which six power plants are currently under construction.

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

The current regulation in Turkey, which is expected to expire on December 2020, support an incentivized FIT of 10.5 US cents per kWh and additional 1.8 US cents per kWh for local manufactured items. This regulation is expected to be changed, but it is not clear yet what will be the actual FIT and other factors related to the incentive plan. It is estimated that the FIT will be lower from the existing one and the structure of the incentivized local manufactured items will also change, to increase the locally made parts. Until this is cleared, and a new regulation will be in place with a new timetable, we estimate that the slowdown in development of new sites will continue.

Latin America

Several Latin American countries have renewable energy programs and pursue the development of the geothermal market. We currently operate in some countries in Latin America and are looking for opportunities in others.

Guatemala

In Guatemala, where our Zunil and Amatitlan power plants are located, the government approved and adopted the Energy Policy 2013-2027 that secure, among other things, a supply of electricity at competitive prices by diversifying the energy mix with an 80% renewable energy share target for 2027.

Honduras

In Honduras, where we operate our Platanares power plant, the government set a target to reach at least 80% renewable energy production by 2034.

Mexico

In Mexico, where we see long-term potential, the Mexican Congress passed, in December 2013, a constitutional reform in an attempt to increase the participation of private investors in the generation and commercialization of electric energy. We have not yet seen yet a notable progress in the development of new geothermal projects.

Caribbean

Many island nations in general and specifically the Caribbean nations, depend almost entirely on petroleum to meet their electricity needs. Caribbean nations have quite significant renewable energy potential, yet most have relatively small demand. Other than in Guadeloupe, where the geothermal power plant that we acquired has been operating since 1985, there are no other operating geothermal projects in the Caribbean region. Although few, we believe there are geothermal opportunities for us in the Caribbean islands of St. Kitts, Nevis, St. Lucia, Dominica, and Montserrat.

New Zealand

In New Zealand, where we have been actively providing geothermal power plant solutions since 1988, the government's policies to fight climate change include a net zero GHG emissions reduction target by 2050 and a renewable electricity generation target of 90% of New Zealand's total electricity generation by 2035. We continue selling power plant equipment to our New Zealand customers, secured two projects in the last two years and intensified our cooperation with other potential customers for adding more geothermal power generation capacity within the coming years.

Asia

Indonesia

In Indonesia, where we hold a 12.75% equity interest in the Sarulla complex, we are currently conducting exploration activity in the Ijen geothermal power plan in East Java, in which we own a 49% equity interest and whose first phase we plan to commission in either 2022 or 2023. The government intends to increase the share of renewable energy sources in the energy mix, aiming to meet a target of 23% of domestic energy demand by 2025, and announced its intention to reduce the country's carbon dioxide emissions by 26% by 2020. Under the current local regulation, the tariff policy for geothermal PPAs is mainly determined based on the location of the relevant power plant.

We consider Indonesia an important geothermal market, where potential for future development is significant along with an active geothermal industry that is supported by regulatory incentives and commitment from the local government.

In addition to project development, we are also pursuing various supply opportunities in Indonesia, and in other countries in Southeast Asia, including several optimization projects.

China

In China, where we supplied our equipment to one of our clients' geothermal projects, the National Energy Administration adopted the 13th Renewable Energy Development Five Year Plan that establishes targets for renewable energy deployment until 2020. Key objectives under the plan include, among others, to increase the share of non-fossil fuel energy in total primary energy consumption to 15% by 2020 and to 20% by 2030, and to increase installed renewable power capacity to 680 GW by 2020.

Japan

The installed capacity of Japan places ninth in the world, the potential output of 23,470 MW is third in the world after United States and Indonesia. In 2018, the Japanese government established as its goal a target of 22% to 24% renewable energy of the Japanese energy installed base by 2030. This outlook expects new geothermal plant installation in the range of 380 MW to 850 MW - 1,000 MW. State-owned resources agency JOGMEC will conduct test bores as part of the financially risky early phase of development on behalf of potential developers starting in the fiscal year from April 2020.

East Africa

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

Kenya

In Kenya, there are already several geothermal power plants, including the only geothermal IPP in Africa, our 150 MW Olkaria III complex. The Kenyan government has identified the country's untapped geothermal potential as the most suitable indigenous source of electricity, and it aspires to reach 5 GW of geothermal power generation by 2030.

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

We consider Kenya an important location for our future growth and we are pursuing geothermal and solar opportunities in the country.

Other Countries

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

Ethiopia electrification targets for 2025 require additional investment in generation capacities. Such growth in demand was expected to be principally met with the Grand Ethiopian Renaissance Dam (GERD). However, IPP's are encouraged to participate directly into the renewable development in order to meet expected local growth. Moreover, the current government sees electricity export to neighboring countries as a strategic asset. The country recently completed an interconnection with Kenya and plan to further increase connections to Djibouti, Sudan, South Sudan, Rwanda, Burundi. These exports will improve foreign exchange reserves in Ethiopia . We hold rights for four geothermal concessions in Ethiopia, for which we have completed initial exploration studies.

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

Other Opportunities

Recovered Energy Generation

In addition to our geothermal power generation activities, we are pursuing recovered energy-based power generation opportunities in the United States and worldwide. We believe recovered energy-based power generation will ultimately benefit from the efforts to reduce GHG emissions. We have built 23 power plants in North America which generate electricity utilizing "waste heat" from gas turbine-driven compressor stations along interstate natural gas pipelines, from midstream and gas processing facilities, and from other applications.

Several states, and to some extent, the federal government, have recognized the environmental benefits of recovered energy-based power generation. For example, 18 states currently allow electric utilities to include recovered energy-based power generation in calculating such utilities' compliance with their mandatory or voluntary RPS and/or Energy Efficient Resources Standards. In addition, California modified the Self Generation Incentive Program to allow recovered energy-based power generation to qualify for a per watt incentive.

Recovery of waste heat is also considered "environmentally friendly" in western Canadian provinces. In 2016, the Canadian government ratified its commitments in the Paris Agreement, which features a commitment to reduce emissions by 30% from 2005 levels by 2030. Pursuant to the Greenhouse Gas Pollution Pricing Act, Canadian provinces must have an emission reduction plan in place or be subject to a federal carbon tax in 2018.

The government of Alberta has introduced the Technology Innovation and Emissions Reduction (TIER) regulation, a plan for reducing emissions, replacing the Carbon Competitiveness Incentive Regulation on January 1, 2020. The TIER regulation applies to Alberta's large industrial facilities that emitted 100,000 tonnes CO2 or more per year of greenhouse gases in 2016, or a subsequent year. Facilities will be subject to a reduction requirement starting at a benchmark of 90% of their prior emissions, then increasing 1% per year after the first year of compliance starting in 2020.

On a federal level, in October 2016, the Government of Canada published the Pan-Canadian Approach to Pricing Carbon Pollution, setting a federal benchmark to ensure that carbon pricing applies to a broad set of emission sources throughout Canada in 2018 with increasing stringency over time. This approach would be flexible and recognize that provinces and territories have implemented or are developing their own carbon pollution pricing systems. The Environment and Climate Change Canada has developed a proposal for regulations pursuant to the Greenhouse Gas Pollution Pricing Act in force June 2018 to implement a carbon pricing system that will apply to facilities carrying out certain industrial activities.

This comprehensive climate policy, once fully implemented, will encourage the development of renewable energy technologies, including waste heat recovery, throughout Canada. We believe that Europe and other markets worldwide may offer similar opportunities in recovered energy-based power generation.

In summary, the market for the recovery of waste heat converted into electricity exists either when already available electricity is expensive or where the regulatory environment facilitates construction and marketing of power generated from recovered waste heat. However, such projects tend to be smaller than 9 MW and we expect any growth to be relatively slow and geographically scattered.

Energy Storage

Globally, there is an increase in the use of renewable energy, mainly due to the continued decline in solar PV prices. In the United States and Europe, this increase is placing strains on the electric grid because adding wind and particularly solar PV power creates situations where a significant amount of power plant capacity must be available to ramp up and down to accommodate wind and mostly solar PV daily output cycles and variations due to atmospheric conditions. Furthermore, the output from wind and solar PV power plants can change significantly over short periods of time due to environmental conditions like cloud movement and fog burn off and cause instability on the electric grid.

As a result, energy management, and especially energy storage is becoming a key component of the future grid. In parallel, we also see movement of C&I and communities toward direct purchases of electricity and an increased focus on reliability of electricity supply.

Energy storage systems utilize surplus, available electricity that enables utilities to optimize the operation of the grid, run generators closer to full capacity for longer periods, and operate the grid more efficiently and effectively. As penetration of wind and solar resources increases, so does the need for services that energy storage systems can provide to "balance the grid", such as local capacity, frequency regulation, ramping, reactive power, black start and movement of energy from times of excess supply to times of high demand. Common applications for energy storage systems include ancillary services, wind/solar smoothing, peaker replacement, and transmission & distribution deferral.

The global energy storage market continues to evolve, with specific applications and geographies leading the market. According to Wood Mackenzie's (formerly GTM Research) Energy Storage Monitor for Q3 2019, approximately 1.1 GWh of new energy storage projects were installed in the United States in 2019 and this number is expected to triple in 2020 to approximately 3.3 GWh.

Significant growth in BESS deployment is already taking place and is expected to continue for both grid-connected (also referred to as "in front of the meter") applications, as well as for "behind the meter" applications, where end-users benefit from savings through demand charge reductions and create revenues through active market participation, and via demand response programs. Many power systems are also undergoing significant changes such as grid aging, grid congestion, retirement of aging generators, implementation of greenhouse gas emission reduction rules and increasing penetration of variable renewable energy resources.

Grid-Connected BESS

We own and operate several grid-connected BESS facilities, where revenues come from selling energy, capacity and/or ancillary services in merchant markets like PJM Interconnect and ISO New England. We are pursuing the development of additional grid-connected BESS projects in multiple regions, with expected revenues coming from providing energy, capacity

and/or ancillary services on a merchant basis, and/or through bilateral contracts with load serving entities, e.g. investor owned utilities, publicly owned utilities and community choice aggregators.

C&I

The electricity industry continues to shift from a purely centralized topology where electricity flows only in one direction from centralized power plants to consumers, into a more distributed architecture, that includes distributed energy resources and consumers selling excess electricity generated on-site to the grid. Many C&I companies are motivated to purchase renewable energy to meet sustainability goals and reduce costs. We see the C&I segment as a natural expansion of our customer base, though our focus is on utility-scale front-of-the-meter applications, where we expect to see higher growth.

solar PV

The solar PV market continues to grow, driven by constant decline in equipment prices and an increasing desire to replace conventional generation with renewable resources, commonly supported by favorable regulatory policies. We are monitoring market drivers with the potential to develop solar PV power plants in locations where we can offer competitively priced power generation. Our current focus is in adding solar PV systems in some of our operating geothermal power plants to reduce internal consumption loads, developing standalone solar PV projects in targeted regions where economics are favorable as well as developing combined solar PV and BESS projects. In 2019 we successfully placed in service a solar PV augmentation system at our Tungsten Mountain geothermal power plant in Churchill County, Nevada. We are also constructing the 20 MW(AC) Wister solar PV project in Imperial County, California, for which a power purchase agreement with San Diego Gas & Electric is in effect and we target commercial operation in 2021. Additional potential projects are undergoing feasibility analysis, and some are in earlier phases of development.

Operations of our Electricity Segment

How We Own Our Power Plants

We customarily establish a separate subsidiary to own interests in each of our power plants. This ensures that the power plant, and the revenues generated by it, will be the only source for repaying indebtedness, if any, incurred to finance the construction or the acquisition (or to refinance the construction or acquisition) of the relevant power 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 interests 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 are Qualifying Facilities under the PURPA and are eligible for regulatory exemptions from most provisions of the FPA and certain state laws and regulations.

How We Explore and Evaluate Geothermal Resources

Since 2006, we have expanded our exploration activities, initially in the United States and in the last few years with an increasing focus internationally. It generally takes two to three years from the time we start active exploration of a particular geothermal resource to the time we have an operating production well, assuming we conclude the resource is commercially viable and determine to pursue its development. Exploration activities generally involve the phases described below.

Initial Evaluation

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

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

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

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

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

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

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

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

Land Acquisition

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

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

Surveys

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

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

Exploratory Drilling

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

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

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

- New data and interpretations obtained concerning the geothermal resource as our exploration activities proceed, and particularly the expected MW capacity power plant the resource can be expected to support. The MW capacity can be estimated using analogous systems and/or quantitative heat in place estimates until results from drilling and flow tests quantify temperature, permeability, and resulting resource size.

- Current and expected market conditions and rates for contracted and merchant electric power in the market(s) to be serviced.

- Availability of transmission capacity.

- Anticipated costs associated with further exploration activities and the relative risk of failure.

- Anticipated costs for design and construction of a power plant at the site.

- Anticipated costs for operation of a power plant at the site, particularly taking into account the ability to share certain types of costs (such as control rooms) with one or more other power plants that are, or are expected to be, operating near the site.

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

How We Construct Our Power Plants.

The principal phases involved in constructing one of our geothermal power plants are as follows:

- Drilling production and injection wells.
- Designing the well field, power plant, equipment, controls, and transmission facilities.
- Obtaining any required permits, electrical interconnection and transmission agreements.
- Manufacturing (or in the case of equipment we do not manufacture ourselves, purchasing) the equipment required for the power plant.
- Assembling and constructing the well field, power plant, transmission facilities, and related facilities.

In recent years, it has taken us two to three years from the time we drill a production well until the power plant becomes operational.

Drilling Production and Injection Wells

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

The cost for each production and injection well varies depending on, among other things, the depth and size of the well and market conditions affecting the supply and demand for drilling equipment, labor and operators. In the last five years, our typical cost for each production and injection well is approximately $3.3 million with a range of $1.0 million to $8.5 million.

Design

We usually use our own employees to design the well field and the power plant, including equipment that we manufacture and that will be needed for the power plant. In some cases, depending on complexity and location, we use third parties to help us with the design. 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 from time to time, depending on complexity and location, outside consultants to obtain any required permits and licenses for our power plants that are not already covered by the terms of our site leases. The permits and licenses required vary from site to site and are described below under “Environmental Permits”.

Manufacturing

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

Construction

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

During fiscal year 2019, in the Electricity segment, we focused on the commencement of operations at Tungsten solar in Nevada and we began with construction of Heber Complex enhancement as well as with enhancement work in some of our operating power plants. During fiscal year 2018, we focused on the commencement of operations at McGinness Hills phase 3 in Nevada and at the Olkaria III plant expansion in Kenya and we began with construction of Steamboat Hills enhancement and Tungsten solar in Nevada as well as with enhancement work in some of our operating power plants. During fiscal year 2017, we focused on the commencement of operations at Platanares power plant in Honduras and Tungsten Mountain in Nevada. We began with construction of the Olkaria III plant expansion in Kenya and enhancement work in some of our operating power plants.

When deciding whether to continue holding lease rights and/or to pursue exploration activity, we diligently prioritize our prospective investments, taking into account resource and probability assessments in order to make informed decisions about whether a particular project will support commercial operation. As a result, during fiscal year 2019 we decided to discontinue our holding in two sites: at Glamis, California and at Lake View, Oregon. We did not have any costs that were capitalized in relation to these sites. During fiscal year 2018 we decided to discontinue our holding in one prospective site: Ruby Valley in Nevada. During fiscal year 2017 we discontinued exploration activities at four prospective sites: the Ungaran region in Indonesia, Glass Buttes - Midnight Point in Oregon and Tuscarora - phase 2 and Don A. Campbell - phase 3, in Nevada.

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

We added to our exploration inventory five prospective sites in 2019, six prospective sites in 2018 and two prospective sites in the year ended 2017.

How We Operate and Maintain Our Power Plants

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 include 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 or electric cooperatives including public owned utilities and recently we signed a PPA with CCAs. Outside of the United States, our purchasers are either state-owned utilities or privately-owned-entities and we typically operate our facilities under rights granted to us by a governmental agency pursuant to a concession agreement. In each case, we enter into long-term contracts (typically, PPAs) for the sale of electricity or the conversion of geothermal resources into electricity. Although previously our power plants' revenues under a PPA generally consisted of two payments, energy payments and capacity payments, our recent PPAs provide for energy payments only. Energy payments are normally based on a power plant's electrical output actually delivered to the purchaser measured in kWh, with payment rates either fixed or indexed to the power purchaser's "avoided" power costs (i.e., the costs the power purchaser would have incurred itself had it produced the power it is purchasing from third parties) or rates that escalate at a predetermined percentage each year. Capacity payments are normally calculated based on the generating capacity or the declared capacity of a power plant available for delivery to the purchaser, regardless of the amount of electrical output actually produced or delivered. In addition, we have six domestic power plants located in California, Nevada and Hawaii that are eligible for capacity bonus payments under the

respective PPAs upon reaching certain levels of generation, or subject to a capacity payment reduction if certain levels of generation are not reached.

How We Finance Our Power Plants

Historically we have funded our power plants with different sources of liquidity such as a non-recourse or limited recourse debt, lease financing, tax monetization transactions, internally generated cash, which includes funds from operation, as well as proceeds from loans under corporate credit facilities and the sale of equity interests and other securities. 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 our power plant subsidiaries to us are contingent on compliance with financial and other covenants contained in the applicable 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".

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

Limited recourse debt refers to project financing as described above with the addition of our agreement to undertake limited financial support for our affiliate that owns the power plant in the form of certain limited obligations and contingent liabilities. These obligations and contingent liabilities may take the form of guarantees of certain specified obligations, indemnities, capital infusions and agreements to pay certain debt service deficiencies. Creditors of a project financing of a particular power plant may have direct recourse to us to the extent of these limited recourse obligations.

We have used financing structures to monetize PTCs and depreciation, such as our recent tax equity partnership transaction involving McGinness Hills phase 3, Tungsten, and an operating lease arrangement for our Puna complex power plants that recently expired in 2019.

We have also used a sale of equity interests in three of our geothermal assets and nine of our REG facilities to fund corporate needs including funding for the construction of new projects. We may use some of the same financing structures in the future.

How We Mitigate International Political Risk.

We generally purchase insurance policies to cover our equity exposure to certain political risks involved in operating in developing countries, as described below under "Insurance". However, insurance may not cover all political risks or coverage amounts may not be sufficient.

Description of Our Leases and Lands

We have domestic leases on approximately 360,224 acres of federal, state, and private land in California, Hawaii, Nevada, New Mexico, Utah Idaho and Oregon. The approximate breakdown between federal, state and private leases and owned land is as follows:

- 80% of the acreage under our control is leased from the U.S. government, acting mainly through the BLM;
- 16% is leased or subleased from private landowners and/or leaseholders;
- 3% is owned by us; and
- 1% is leased from various states.

Each of the leases within each of the categories above has standard terms and requirements, as summarized below. Internationally, our land position includes approximately 60,903 acres.

BLM Geothermal Leases

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

BLM geothermal leases grant the geothermal lessee the right and privilege to drill for, extract, produce, remove, utilize, sell, and dispose of geothermal resources on certain lands, together with the right to build and maintain necessary improvements thereon. The actual ownership of the geothermal resources and other minerals beneath the land is retained in the federal mineral estate. The geothermal lease does not grant to the geothermal lessee the exclusive right to develop the lands, although the geothermal lessee does hold the exclusive right to develop geothermal resources within the lands. Since 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, including use, off-road vehicles, and/or wind or solar energy developments.

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

BLM leases issued after August 8, 2005 have a primary term of ten years. If the geothermal lessee does not reach commercial production within the primary term, the BLM may grant two five-year extensions. If the lessee is drilling a well for the purposes of commercial production, the lease may be extended for five years and thereafter as long as steam is being produced and used in commercial quantities the lease may be extended for up to 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 under terms and conditions as the BLM deems appropriate.

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

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

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

Private Geothermal Leases

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

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

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

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

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

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

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

Description of Our Power Plants

Domestic Operating Power Plants

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

Power plants in the United States

Project Name	Size(MW)	Technology	Resource Cooling	Customer	PPA Expiration
Brawley [1]	13	Geothermal water-cooled binary system	Depends on the mix of used production wells	SCE	2031
Brady Complex	26	Geothermal air and water-cooled binary system	Brady - 2.6°F per year Desert Peak 2 - 2°F per year		Brady — 2022 Desert Peak 2 — 2027
Don A. Campbell Complex [2]	36	Geothermal air cooled binary system	Testing is in process to confirm the impact on temperature decline	SCPPA	Phase 1 - 2034 Phase 2 - 2036
Heber Complex [3]	81	Geothermal dual flash and binary systems using a water cooled system	1°F per year	SCPPA	Heber 1 — 2025 Heber 2 — 2023 Heber South — 2031
Jersey Valley	10	Geothermal air cooled binary system	3°F per year	Nevada Power Company	2032
Mammoth Complex	29	Geothermal air cooled binary system	Less than 0.5°F per year	PG&E and Southern California Edison.	G-1 and G-3 - 2034 G-2 plant - 2027
McGinness Hills Complex	143	Geothermal air cooled binary system	Initial declined of 3°F observed in the past year	Nevada Power Company and SCPPA.	Phases 1 and 2 - 2033 Phase 3 - 2043.
Neal Hot Springs [4]	22	Geothermal air cooled binary system	1°F over the past year	Idaho Power Company	2038
OREG 1 [2]	22	Geothermal air cooled binary system	NA	Basin Electric Power Cooperative	2031
OREG 2 [2]	22	Geothermal air cooled binary system	NA	Basin Electric Power Cooperative	2034
OREG 3 [2]	5.5	Geothermal air cooled binary system	NA	Great River Energy.	2029
OREG 4	3.5	Geothermal air cooled binary system	NA	Highline Electric Association.	2029
Ormesa Complex [5]	39	Geothermal water-cooled binary system and water-cooled flash system.	Less than 1°F per year	SCPPA under a single PPA.	2042
Puna Complex [2],[6]	38	Geothermal combined cycle and air cooled binary system	The resource temperature was stable prior to the volcano eruption. The shut- down of the power plant resulted in some increase in temperature, and reservoir studies are underway to quantify any changes	HELCO	2027

Raft River	11	Geothermal water-cooled binary system	No cooling	Idaho Power Company.	2032
San Emidio [7]	11	Geothermal- water-cooled binary system	3°F per year	NV Energy.	2038
Steamboat Complex [8]	65	Geothermal air and water-cooled binary system and a single flash system	Lower Steamboat - between 2°F to 3°F per year Steamboat Hills 4°F per year	* Steamboat 2 & 3- Sierra Pacific Power Company * Galena1 & 3- Nevada Power Company * Galena 2 & Steamboat Hills- SCPPA	Steamboat 2 and 3- 2022 Galena1- 2026 Steamboat Hills and Galena 2 - 2043 Galena 3- 2028
Tungsten Mountain Geothermal [9]	27	Geothermal air and water-cooled binary system	1°F per year	SCPPA	2043
Tungsten Mountain solar	7	solar PV System	NA	SCPPA	2043
Tuscarora [10]	18	Geothermal water-cooled binary system	We expect continued gradual decline in the cooling rate from less than 3°F per year to less than 1°F per year over the long term	Nevada Power Company.	2032

Power plants in Rest of the World

Project Name	**Size (MW)**	**Technology**	**Resource Cooling**	**Customer**	**PPA Expiration**
Amatitlan (Guatemala) [11]	20	Geothermal air cooled binary system and a small back pressure steam turbine (one MW)	Stable	INDE and another local purchaser.	2028.
Bouillante (France) [12]	15	Geothermal direct steam turbines.	Stable	EDF pursuant to a PPA.	2030
Olkaria III Complex (Kenya)	150	Geothermal air cooled binary system	Less than1°F per year	KPLC	Plant 2 - 2033 Plant 1&3 - 2034 Plant 4 - 2036
Platanares (Honduras) [13]	38	Geothermal air cooled binary system	2°F per year	ENEE pursuant to a PPA.	2047
Sarulla Complex - (Indonesia) [14]	330 (our share is 42)	Geothermal Combined Cycle steam and binary systems	Stable	PLN	2047
Zunil (Guatemala) [15]	20	Geothermal air cooled binary system	Stable	ENDE	2034

(1) A new production well was drilled and added to the production header in 2019 and, as a result, we have seen an increase in generation.

(2) Indirectly owned 36.75% by Northleaf.

(3) We are currently in the process of enhancing the Heber 1 and Heber 2 power plants as discussed below.

(4) Owned 40% by Enbridge Inc. Upgrades to the power plant are in progress and expected to be completed in 2020.

(5) We are currently in the process of replacing old equipment at Ormesa with new technology equipment.

(6) On May 3, 2018, the Kilauea volcano located in close proximity to our Puna 38 MW geothermal power plant in the Puna district of Hawaii's Big Island erupted following a significant increase in seismic activity in the area. The power plant was shutdown immediately and has not been in operation since then. Following the lava flow stop, we have been working to bring the power plant back to operation, as discussed under "Recent Developments" under Item 7 - "Management's Discussion and Analysis of Financial Condition and Results of Operations". Recently, we have reached an agreement with HELCO and signed a new PPA that was filed with the local PUC for approval. The new PPA extends the current term until 2052 and increases the current contract capacity by 8 MW to 46MW. In addition, the new PPA has a fixed price with no escalation, regardless of changes to fossil fuel pricing, which impacts the majority of our current pricing under the existing PPA. See "Recent Developments" under Item 7 - "Management's Discussion and Analysis of Financial Condition and Results of Operations".

(7) A new production well was brought online in 2019, increasing the production temperature and flow.

(8) In Steamboat Hills we are replacing all the equipment and expect to add to the existing projects approximately 19MW, which is expected to be online in 2020. See below "Steamboat Hills Enhancement".

(9) We installed a solar PV system in the Tungsten Mountain geothermal power plant to reduce internal load (i.e. parasitic).

(10) During 2019 the Tuscarora power plant was upgraded to utilize air cooling systems, which reduces the need for make-up water.

(11) Steam gathering system and heat exchangers at the Amatitlan power plant were improved in 2019.

(12) 85% of the Bouillante power plant is owned jointly by Ormat and CDC allocated 75% to Ormat and 25% to CDC.

(13) We hold the Platanares assets, including the project's wells, land, permits and a PPA, under a BOT structure for 15 years from the date the Platanares plant commenced commercial operation on September 26, 2017. A portion of the land on which the project is located is held by us through a lease from a local municipality.

(14) The Sarulla complex experienced a reduction in generation due to well field issues at the NIL power plants.

(15) In January 2014, we signed an amendment to the PPA with INDE to extend its term by 15 years until 2034. The PPA amendment also transfers operation and management responsibilities of the Zunil geothermal field from INDE to Ormat for the term of the amended PPA in exchange for an increase in tariff. Additionally, INDE exercised its right under the PPA to become a partner in the Zunil power plant and to hold a 3% equity interest.

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

- Capacity payment:
  - From 2019 and thereafter, the capacity payment will be based on actual delivered capacity and the capacity rate will be reduced.
- Energy payment:
  - Energy payment will include a geothermal field operation and maintenance rate based on actual delivered energy in addition to the energy rate on actual delivered energy.
  - The energy rate on delivered energy will increase and will compensate the reduction in the capacity rate.

Future Projects

Projects Released for Construction

We have several projects in various stages of construction, including four projects that we have fully released for construction and one project that is in the early stage of construction.

These projects are expected to have a total geothermal generating capacity between 70 MW and 75 MW (representing our interest) and one 20 MW solar PV project.

Project Name	**Expected Size (MW)**	**Technology**	**Customer**	**Expected COD**	**Current Condition**
Heber Complex	11	Geothermal air-cooled binary system	SCE and SCPPA	Early 2021	Permitting, Engineering and procurement ongoing. Manufacturing and construction commenced.
Steamboat Hills Enhancement	19	Geothermal air-cooled binary system	SCPPA	First half of 2020	Equipment delivered to site. Construction ongoing
CD4	30	Geothermal air-cooled binary system	SCPPA - 16 MW 14MW Silicon Valley Clean Energy - 14 MW Monterey Bay Community Power - 14 MW	End 2021	Engineering and procurement commenced
Wister solar	20 AC	solar PV	SDG&E	2021	Engineering and procurement ongoing
Carson Lake	10 - 15	Geothermal air-cooled binary system	No PPA	TBD	Early stage of construction

Projects under Various Stages of Development that were not Released for Construction

We also have projects under various stages of development in the United States, Kenya and Guadeloupe. 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 our geothermal projects would increase by approximately between 71 MW to 76 MW (representing our interest). However, we prioritize our investments based on their readiness for continued construction and expected economics and therefore we are not planning to invest in all of such projects in 2020.

Project	Location	Technology	Size (MW)	Customer	Expected COD
Bouillante power plant	Guadeloupe	Geothermal	10	Under discussion with EDF	2022
Dixie Meadows	Nevada, U.S.	Geothermal	15	TBD	2022
Steamboat solar	Nevada, U.S.	solar PV	5 AC	SCPPA	2022
North Valley	Nevada, U.S.	Geothermal	15 - 20	SCPPA	2022
Puna Expansion	Hawaii, U.S.	Geothermal	8	HELCO	2022
Olkaria III Expansion	Kenya	Geothermal	10	KPLC	2022
McGinness Hills Expansion	Nevada, U.S.	Geothermal	8	SCPPA	2021

Future Prospects

We have a substantial land position that is expected to support future development and on which we have started or plan to start exploration activity. When deciding whether to continue holding lease rights and/or to pursue exploration activity, we diligently prioritize our prospective investments, taking into account resource and probability assessments in order to make informed decisions about whether a particular project will support commercial operation.

During fiscal year 2019, we discontinued holding a lease at two prospects at Glamis, California and at Lake View, Oregon. We added five new prospects in 2019, in the United States and Indonesia.

Our current land position is comprised of various leases, concessions and private land for geothermal resources of approximately 254,000 acres in 41 prospects including the following:

Nevada (22)

1.	Alum	Exploration studies in progress;
2.	Baltazor	Under exploration drilling;
3.	Colado	Under exploration drilling;
4.	Crescent Valley	Under exploration drilling;
5.	Comstock (formerly Dixie Comstock)	Under exploration drilling;
6.	Edwards Creek	Under exploration drilling;
7.	Emigrant	Exploration studies in progress;
8.	Gerlach	Under exploration drilling;
9.	Horsehaven (formerly Beowawe)	Exploration studies in progress;
10.	Lee Hot Springs	Exploration studies in progress;
11.	Mary's River	Exploration studies in progress;
12.	North Valley	Exploration studies in progress;
13.	Juniper (formerly North Valley 2)	Under exploration drilling;
14.	New York Canyon	Under exploration drilling;
15.	Pearl Hot Springs	Exploration studies in progress;
16.	Pinto Hot Springs	Exploration studies in progress;
17.	Rhodes Marsh	Exploration studies in progress;
18.	South Brady	Exploration studies in progress;
19.	Trinity	Exploration studies in progress;
20.	Tungsten Mountain – Phase 2	Assessment for future expansion;
21.	Tuscarora 2	Assessment for future expansion; and
22.	Twin Buttes	Lease acquired but no further action has been taken yet.

California (4)

1.	Geysers	Exploration studies in progress;
2.	Rhyolite Plateau	Exploration studies in progress;
3.	Sandpiper	Exploration studies in progress; and
4.	Truckhaven	Exploration studies in progress.

Oregon (2)

1.	Crump Geyser	Under exploration drilling; and
2.	Vale	Exploration studies in progress.

New Mexico (1)

1.	Rincon	Exploration studies in progress.

Utah (2)

1.	Pavant	Exploration studies in progress; and
2.	Roosevelt Hot Springs	Exploration studies in progress.

Guatemala (2)

1.	Amatitlan Phase II	Exploration studies in progress; and
2.	Tecumburu	Exploration studies in progress.

New Zealand (1)

1.	Tikitere	Signed BOT agreement; exploration activity is on hold.

Honduras (1)

1.	San Ignacio (12 Tribes)	Exploration studies in progress.

Indonesia (2)

1.	Bitung	Exploration studies in progress; and
2.	Ijen	Exploration studies in progress.

Ethiopia (4)

1.	Boku	Under exploration studies;
2.	Dofan	Under exploration studies;
3.	Dugumo Fango	Under exploration studies; and
4.	Shashamane	Under exploration studies.

Operations of our Product Segment

Power Units for Geothermal Power Plants

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

The power units are usually paid for in installments, in accordance with milestones set forth in the supply agreement. We also provide the purchaser with spare parts (either upon their request or our recommendation). We provide the purchaser with at least a 12-month warranty for such products. We provide the purchaser with performance guarantees (usually in the form of standby letters of credit), which partially terminates upon delivery of the equipment to the site and terminates in full at the end of the warranty period.

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 manufacture and sell the power units for recovered energy-based power generation to third parties for use in "inside-the-fence" installations or otherwise. Our customers include gas processing plant owners and operators, cement plant owners and operators and companies in the process industry.

Remote Power Units and other Generators

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

EPC of Power Plants

We engineer, procure and construct, as an EPC contractor, geothermal and recovered energy power plants on a turnkey basis, using power units we design and manufacture. Our customers are geothermal power plant owners as well as our target customers for the sale of our recovered-energy based power units described above. Unlike many other companies that provide EPC services, we believe that our advantage is in using our own manufactured equipment and thus have better quality and control over the timing and delivery of equipment and related costs. The consideration for such services is usually paid in installments, in accordance with milestones set forth in the EPC contract and related documents. We provide performance guarantees (usually in the form of standby letters of credit) securing our obligations under the contract.

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

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

Backlog

We have a product backlog of approximately $141.9 million as of February 25, 2020, which includes revenues for the period between January 1, 2020 and February 25, 2020, compared to $216.8 million as of February 25, 2019, which included revenues for the period between January 1, 2019 and February 25, 2019.

The following is a breakdown of the Product segment backlog amount (in $ millions) by countries as of February 25, 2020:

Country	Backlog Amount	Percentage of Backlog
Turkey	64.0	45.1 %
Chile	34.9	24.6 %
New Zealand	34.1	24.0 %
Taiwan	2.8	2.0 %
U.S.	2.5	1.8 %
Bolivia	2.4	1.7 %
Others	1.2	0.8 %
Total	141.9	

The following is a breakdown of the Product segment backlog by technology as of February 25, 2020:

	% of Total Backlog	Latest Expected Completion
Geothermal	98.1%	2020
Recovered Energy	0.1%	2020
Other	1.8%	2020

Operations of our Energy Storage and Management Services Segment

Storage Projects

In addition to our Geothermal activity, we own and operate as well as working to develop energy storage projects in the United States including the following:

Under operation

Project Name	Customer	Location	Size (MW)	Duration (hours)	Type of contract
ACUA	PJM	NJ	1	1	Merchant
Plumsted	PJM	NJ	20	1	Merchant
Stryker	PJM	NJ	20	1	Merchant
Hinesburg	ISONE	VT	2	2.5	Merchant

Under construction and development

Project Name	Customer	Location	Size (MW)	Duration (hours)	Type of contract
Rabitt Hills	ERCOT	TX	10	1.25	Merchant
Valecito	CAISO	CA	10	4	Capacity PPA and Merchant

Energy Storage Pipeline

For an energy storage prospect to to move into the EPC phase, it requires an executed site control, interconnection agreement, permits from all authorities and a viable financial model. We have a substantial pipeline for future development in the United States that and we expect to commission between 150 MW and 200 MW between 2020 and 2022.

Competition

Electricity Segment

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

Competition in the Electricity segment is particularly marked in the very early stage of either obtaining the rights to the resource for development of future projects or acquiring a site already in a more advanced stage of development. From time to time and in different jurisdictions competing geothermal developers become our customers in the Product segment.

Our main competitors in the geothermal sector in the United States are CalEnergy, Calpine Corporation, Terra-Gen Power LLC, Enel Green Power S.p.A., Cyrq Energy Inc. and other smaller pure play developers. Outside the United States, in many cases our competitors are companies that are gaining experience developing geothermal projects in their own countries such as Mercury (formerly Mighty River Power) and Contact Energy in New Zealand, and local developers and steam turbine manufacturers in Indonesia. Some of our competitors are now seeking to take the local experience they have gained and develop geothermal projects in other countries. These competitors include Energy Development Corporation from the Philippines and Enel Green Power from Italy. Some Turkish developers are also focusing on the international market. Additionally, we face competition from small country-specific companies.

In obtaining new PPAs, we also face competition from companies engaged in the power generation business from other renewable energy sources, such as wind power, biomass, solar power and hydroelectric power. Increasingly we compete against these technologies combined with energy storage. In the last few years, competition from the wind and solar power generation developers has increased significantly.

As a geothermal company, we are focused on niche markets where our baseload and flexibility advantages can allow us to develop competitive projects.

Product Segment

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

Our competitors among power plant equipment suppliers are divided by technology, steam turbines and binary power plant manufacturers. Our main steam turbines manufacturers competitors are industrial steam turbine manufacturers such as Mitsubishi Heavy Industries, Fuji Electric Co., Ltd. and Toshiba Corporation of Japan, GE/Nuovo Pignone brand and Ansaldo Energia of Italy.

Our binary technology competitors are binary systems manufacturers using the ORC such as Fuji Electric Co., Ltd of Japan, Mitsubishi Heavy Industries through Turboden, TICA, a Chinese air conditioning company who recently acquired Italian Exergy, Egesim, a Turkish electrical contractor who is collaborating with Atlas Copco mainly in the Turkish market and internationally, and Kaishan, a compressor manufacturer from China who develops its own projects. While we believe that we have a distinct competitive advantage based on our accumulated experience and current worldwide share of installed binary generation capacity (which is approximately 82%), an increase in competition, which we are currently experiencing, has started to affect our ability to secure new purchase orders from potential customers. The increased competition led to a reduction in the prices that we are able to charge for our binary equipment, which in turn impacted our profitability.

In the REG business, our competitors are other ORC manufacturers (such as GE, Exergy and Mitsubishi/Turboden), manufacturers that use Kalina technology (such as Geothermal Energy Research & Development Co., Ltd in Japan), other manufacturers of conventional steam turbines and small developers of small scale ORCs.

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

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

Energy Storage and Management Services Segment

In our Energy Storage and Management Service segment, we face competition from companies that already have established businesses in those technologies and markets as well as companies seeking to acquire established businesses and other new market entrants like us.

In the demand response markets, our Viridity business competes primarily with specialized demand management providers and traditional curtailment service providers. Viridity differentiates itself from its competitors by its proprietary software and analytical strengths, wider use cases, customer base, business model, and market presence.

The energy storage and energy management space is comprised of many companies divided into different verticals and sub verticals like independent power producers, project developers, system integrators, EPC providers, hardware suppliers (e.g. batteries, inverters, and balance of plant), scheduling coordinators, software suppliers, etc. Our proprietary software, analytical operational platform and experience in storage operation and integration with electricity markets, as well as our engineering capabilities, allow us to provide multiple value streams (value stacking) from a single storage installation. We have continued and plan to continue to grow our Viridity business in these markets.

Customers

All of our revenues from the sale of Electricity in the year ended December 31, 2019 were derived from fully-contracted energy and/or capacity payments under long-term PPAs with governmental or private utility entities. The percentage of total revenues above 5% is detailed in the table below:

Utility	% of total revenues for the year ended December 31, 2019
NV Energy	17.1%
SCPPA	17.9%
KPLC	16.3%

Based on publicly available information, as of December 31, 2019, the credit ratings of our rated electric utility customers are as set forth below:

Issuer	Standard & Poor's Ratings Services	Moody's Investors Service Inc.
Southern California Edison	BBB (Stable)	Baa2 (Stable)
HELCO	BBB- (Stable)	Ratings withdrawn
Sierra Pacific Power Company	A (Stable)	Baa1 (Stable)
Nevada Power Company	A (Stable)	Baa1 (Stable)
SCPPA	BBB+ (Stable)	Aa2 (Stable)
PG&E	D (NM)	Ratings withdrawn
EDF	A- (Negative)	A3 (Stable)

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.

While we have historically been able to collect on substantially all of our receivable balances, we have received late payments and have amounts overdue from KPLC in Kenya related to our Olkaria III Complex and from ENEE in Honduras related to our Platanares power plant. We believe we will be able to collect all past due amounts.

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

Raw Materials, Suppliers and Subcontractors

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

We use subcontractors for some of the manufacturing activities with respect to our products components and for construction activities with respect to 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 ourselves, if necessary or desirable, without adverse effect to our operations.

Employees

As of December 31, 2019, we employed 1,408 employees, of whom 584 were located in Israel, 578 were located in the United States and 246 were located in other countries. We expect that future growth in the number of our employees will be mainly attributable to the purchase and/or development of new power plants.

As of December 31, 2019, the only employees that are represented by a labor union are the employees of our recently acquired Bouillante power plant located in Guadeloupe. The employees in Guadeloupe are represented by the Confédération Générale du Travail de Guadeloupe. We have never experienced any labor dispute, strike or work stoppage. We consider our relations with our employees to be satisfactory. We believe our future success will depend on our continuing ability to hire, integrate, and retain qualified personnel.

In the United States, we currently do not have employees represented by unions that we recognize under collective bargaining agreements.

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

Insurance

We maintain business interruption insurance, casualty insurance, including flood, volcanic eruption, earthquake and cyber coverage as it relates to our property insurance policy, general liability, primary and excess liability, environmental and pollution liability, control of wells, drilling rigs, construction risks, as well as customary worker's compensation and automobile, marine transportation insurance and such other commercial insurance as is generally carried by companies engaged in similar businesses and owning similar properties in the same general areas as us. To the extent any such casualty insurance covers us and/or any of our owned, controlled, direct or indirect affiliated or associated companies, subsidiary companies or corporations in an amount based upon the estimated replacement value and maximum foreseeable loss 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 coverage in an amount that also varies from power plant to power plant. As an exception, at this stage we have not secured business interruption coverage for our Puna power plant in Hawaii.

We generally purchase insurance policies to cover our equity exposure to certain political risks involved in operating in developing countries. We hold a global political risk insurance program for two to three years covering the significant political risk we identified as described below. This global program is issued by the global lead insurers in the private sector. Currently we hold such insurance for our Zunil, Amatitlan, Olkaria III, Platanares and Sarulla operating power plants. Such insurance policies generally cover, subject to the limitations and restrictions contained therein, losses derived from a specified governmental act, such as confiscation, expropriation, riots, and the inability to convert local currency into hard currency and, in certain cases, the breach of agreements with governmental entities, up to approximately 90% of our net equity investment.

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

PURPA provides the owners of power plants certain benefits described below if a power plant is a "Qualifying Facility." A small power production facility is a Qualifying Facility if: (i) the facility does not exceed 80 MW; (ii) the primary energy source of the facility is biomass, waste, geothermal, or renewable resources, or any combination thereof, and at least 75% of the total energy input of the facility is from these sources, and fossil fuel input is limited to specified uses; and (iii) the facility, if larger than one megawatt, has filed with FERC a notice of self-certification of qualifying status, or has been certified as a Qualifying Facility by FERC. 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 not later than December 31, 1994, and construction of the facility commenced not later than December 31, 1999.

With respect to the FPA, FERC's regulations under PURPA do not exempt from the rate provisions of the FPA sales of energy or capacity from Qualifying Facilities larger than 20 MW in size that are made (a) pursuant to a contract executed after March 17, 2006 or (b) not pursuant to a state regulatory authority's implementation of PURPA. The practical effect of these regulations is to require owners of Qualifying Facilities that are larger than 20 MW in size to obtain market-based rate authority from FERC if they seek to sell energy or capacity other than pursuant to a contract executed on or before March 17, 2006 or pursuant to a state regulatory authority's implementation of PURPA.

In addition, provided that the purchasing electric utility has not been relieved from its mandatory purchase obligation, PURPA and FERC's regulations under PURPA obligate electric utilities to purchase energy and capacity from Qualifying Facilities at either the electric utility's avoided cost or a negotiated rate. FERC's regulations under PURPA allow FERC, upon request of a utility, to terminate a utility's obligation to purchase energy from Qualifying Facilities upon a finding that Qualifying Facilities have nondiscriminatory access to: (i) independently administered, auction-based day ahead, and real time markets for electric energy and wholesale markets for long-term sales of capacity and electric energy; (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, including long-term and short-term sales, and electric energy, including long-term, short-term, and real-time sales, to buyers other than the utility to which the Qualifying Facility is interconnected; or (iii) wholesale markets for the sale of capacity and electric energy that are at a minimum of comparable competitive quality as markets described in (i) and (ii) above. FERC regulations protect a Qualifying Facility's rights under any contract or obligation involving purchases or sales that are entered into before FERC has determined that the contracting utility is entitled to relief from the mandatory purchase obligation. FERC has granted the request of California investor-owned utilities for a waiver of the mandatory purchase obligation for Qualifying Facilities larger than 20 MW in size. FERC is re-evaluating aspects of its PURPA regulations, including the 20 MW threshold.

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

PUHCA

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

FPA

Pursuant to the FPA, FERC has exclusive jurisdiction over the rates for most wholesale sales of electricity and transmission in interstate commerce. These rates may be based on a cost of service approach or may be determined on a market basis through competitive bidding or negotiation. FERC can accept, reject or suspend rates. The rates can be suspended for up to five months, at which point the rates become effective subject to refund. FERC can order refunds for rates that are found to be "unjust and unreasonable" or "unduly discriminatory or preferential."

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 and/or a reduction in future payments. In addition, the loss of any such status would result in the occurrence of an event of default under indenture for 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.

Additionally, FERC possesses civil penalty authority, up to approximately $1.3 million per violation of the FPA per day. FERC can also require the disgorgement of unjust profits earned in connection with such violations of the FPA and revoke the right of the power plants to make sales at market-based rates.

Under the Energy Policy Act of 2005, the FPA was supplemented to empower FERC to ensure the reliability of the bulk electric system. Such authority required that FERC assume both oversight and enforcement roles. Pursuant to its new directive, FERC certified the North American Electric Reliability Corporation as the nation's Electric Reliability Organization (ERO) to develop and enforce mandatory reliability standards to address medium and long-term reliability concerns. Today, enforcement of the mandatory reliability standards, including the protection of critical energy infrastructure, is a substantial function of the ERO and of FERC, which may impose penalties of up to approximately $1.3 million a day for violating mandatory reliability standards.

Thus, if any of the power plants were to lose Qualifying Facility status, the application of the FPA and other applicable state regulations to such power plants could require compliance with an increasingly complex regulatory regime that may be costly and greatly reduce our operational flexibility. Even if a power plant does not lose Qualifying Facility status, the owner of a Qualifying Facility/power plant in excess of 20 MW will become subject to rate regulation under the FPA for sales of energy or capacity pursuant to a contract executed after March 17, 2006 or not pursuant to a state regulatory authority's implementation of PURPA. A decrease in existing rates or being ordered by FERC to pay refunds for rates found to be "unjust and unreasonable" or "unduly discriminatory or preferential" would likely result in a decrease in our future revenues.

State Regulation

Our power plants in California, Nevada, Oregon, and Idaho, 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, SCPPA and Idaho Power Company). All of the utilities except SCPPA are regulated by their respective state public utilities commissions. Sierra Pacific Power Company and Nevada Power Company, which merged and are doing business as NV Energy, are regulated by the PUCN. Southern California Edison is regulated by the CPUC.

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

Environmental Permits

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

The second category of permitting focuses on the installation and use of the geothermal wells themselves. Geothermal projects typically have three types of wells: (i) exploration wells designed to define and verify the geothermal resource, (ii) production wells to extract the hot geothermal liquids (also known as brine) for the power plant, and (iii) injection wells to inject the brine back into the subsurface resource. For example, on BLM lands in Nevada, California, Oregon, and Idaho, 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 UIC permits from the Nevada Division of Environmental Protection and Bureau of Water Pollution Control. All geothermal wells drilled in Oregon require a geothermal well drilling permit from the Oregon Department of Geology and Mineral Industries. All geothermal wells drilled in Idaho require a well construction permit from the IDWR and injection wells also require UIC permitting through IDWR. Geothermal wells on private lands in California require drilling permits from the California Department of Conservation's DOGGR. The eventual designation of these installed wells as individual production or injection wells and the ultimate closure of any wells is also reviewed and approved by DOGGR pursuant to a DOGGR-approved Geothermal Injection Program.

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

A fourth category of permits, required in Nevada, California, Oregon, and Idaho, includes ministerial permits such as building permits, hazardous materials storage and management permits, and pressure vessel operating permits. We are also required to obtain water rights permits in Nevada if water cooling is being used at the power plant. 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 that may modify the time to receive such permits and associated costs of compliance.

Our BESS projects are subject to similar permitting and regulatory compliance requirements. All of our current BESS projects are located on privately owned land and may require ministerial permits from local agencies as described above or undergo a state environmental permitting process (e.g., under the California Environmental Quality Act) with the city or county as the lead permitting agency. Storage projects are also required to comply with all applicable federal, state, and local laws and regulations, and similar to geothermal projects, storage projects may require various regulatory plans and programs including emergency action plans and fire response plans.

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

Environmental Laws and Regulations

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

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

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.

Regulation Related to New Activity

Our recent entry into the energy storage space and planned provision of energy management and demand response require us to obtain and maintain certain additional authorizations and approvals. These include (1) authorization from FERC to make wholesale sales of energy, capacity, and ancillary services at market-based rates, and (2) membership status with eligibility to serve designated contractual functions in the ISO/RTOs of PJM, NYISO, and ERCOT. In the future, we may need to obtain and maintain similar membership and eligibility status with other ISO/RTOs in order to offer such services in their respective areas.

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

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

Guatemala

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

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 major licensed public electricity supplier and has a virtual monopoly in the distribution of electricity in the country with the exception of a few off-grid, which have recently been licensed by the ERPA. 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 ERPA under the Kenyan Energy Act. KPLC's retail electricity rates are subject to approval by the ERPA. The ERPA 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. Renewable energy (principally solar, wind and biomass) is now one of the key energy sub-sectors in Kenya contributing significantly to the overall energy mix as a result of the implementation of the feed-in- tariff policy by the Ministry of Energy. Under the national constitution enacted in August 2010, formulation of energy policy (including electricity) and energy regulation are functions of the national government. However, the constitution lists the planning and development of electricity and energy regulation as a function of the county governments (i.e. the regional or local level where an individual power plant is or is intended to be located).

Indonesia

The 2009 Electricity Law divided the power business into two broad categories: (1) activities that supply electrical power, both public supply and captive supply (own use), such as electrical power generation, electrical power transmission, electrical power distribution and the sale of electrical power and (2) the activities involved in electrical power support such as service businesses (consulting, construction, installation, operation & maintenance, certification & training, testing etc.) and industry businesses (power tools & power equipment supply). Currently, power generation is dominated by PLN (state owned company), which controls around 70% of generating assets in Indonesia. Private sector participation is allowed through an IPP scheme . IPP appointment is done most often through tenders although IPPs can be directly appointed or selected. The law provides PLN priority rights to conduct its business nationwide . As the sole owner of transmission and distribution assets, PLN remains the only business entity involved in transmitting and distributing although the Law allows private participation. The Geothermal Law issued in 2014, endorses private participation as Geothermal IPP. The Geothermal IPP appointment is done through tender held by the Central Government. The Central Government also awards the tender winner a Geothermal License (IPB). Accordingly, the Geothermal License holder can conduct exploration and feasibility studies within five years subject to two one-year extensions, conduct well development and power plant construction and sell the electricity generated to PLN for a maximum of 30 years. Prior to the expiration of the Geothermal License, the IPP can propose to extend the license for an additional 20 years. Starting in 2017, the regulatory framework with respect to tariffs is based on PLN's existing average cost of generation (known by its Indonesian acronym, BPP) with respect to the relevant local grid cost of generation, excluding transmission and distribution costs. The Minister of Energy releases each year a list of local BPPs for each region, and the national BPP (which is an average of the local BPPs). The BPPs for a particular year are based on PLN's previous year audited generation costs. For 2017, the national BPP was set at Rp 983/kWh (equivalent to US$ cent 7.39/kWh at Rp 13,307/US$) based on PLN's 2016 audited generation costs. For geothermal, the tariff was assumed as follows: (i) if the local BPP is higher than the national BPP, the maximum tariff is the local BPP, (ii) if the local BPP is lower than or the same as the national BPP, the tariff is based on mutual agreement between PLN and the IPP. Presently, this tariff regulation has been revoked, and the government is assessing a plan to adopt a Feed in Tariff scheme for Geothermal and Renewable Energy IPP.

Guadeloupe

EDF is the transmission and distribution utility in Guadeloupe and also operates a significant portion of Guadeloupe's fossil energy generation. There are also a number of IPPs in Guadeloupe, primarily producing renewable electricity. The electricity sector in Guadeloupe is regulated by the Commission Regulation of Energy (CRE), which also regulates EDF's operations in mainland France and its other overseas territories. The electricity sector in Guadeloupe is characterized by both enabling features and obstacles with respect to renewable energy. One of the most influential enabling features is a French law requiring the utility to purchase power from any interconnected renewable generator. The major obstacle preventing further uptake of renewable electricity generation is the cap on variable generation at 30% of instantaneous system load.

Honduras

In 2014, Honduras approved its new Law of Electrical Industry (Decree 404-2013, and its Regulation, published in the Official Newspaper on November 18, 2015; and by Executive Accord 07-2015), which provides the legal framework for the electricity sector and replaces the previous Electricity Subsector Framework Law (Decree 158 of 1994, regulated by Accord 934 of 1997). The Law establishes technology-specific auctions for renewable energy. It creates the Regulatory Commission of Electric Power (CREE) as the entity in charge of supervising the bidding processes and the awarding of PPAs. The CREE is also responsible for granting study permits for the construction of generation projects that use renewable natural resources. Permits will have a maximum duration of two years, and will be revoked if no studies have been initiated within a period of six months and the reports required by the CREE have not been submitted. The new Law also establishes that all new capacity must be contracted through auctions and that the government can set a minimum quota for renewables in each auction. With respect to metering, after previous regulation applied legal incentives to renewable energy metering, the new law mandates utilities to buy excess power and credit it towards monthly bills and to install bi-directional meters.

Among others, the objectives of the law are to adapt the electricity sector's legislation to the Framework Treaty for the Central American Electricity Market, which Honduras is a party to, and update the operating rules in the country's electricity industry by incorporating structures and modern practices to increase the sector's efficiency and competency in the production and marketing of electricity services.

With the passage of this new law, Honduras is moving into a new and open market. Under this legislation, all aspects of the market have been opened to private parties. This legislation is still being implemented within the market.

Honduras has also approved a Law of Incentives for Renewable Energy Projects, Decree 70-2007, further amended by Decree 138-2013, with additional incentives to solar PV projects, etc. The purpose, as in other countries of the region, is to promote the development of renewable energy power plants. Laws provide certain benefits to companies that generate power through renewable sources, including a 10-year exemption from corporate income tax and VAT on imports and customs duties, a fast track process for certain permits and a Sovereign Guaranty by the Central Government for the payments of the off-taker, the Public Utility Company, ENEE. At present, the Law of the Electrical Industry and the Laws of Incentives for Renewable Energy Projects are still in force.

ITEM 1A. RISK FACTORS

The following risk factors should be read carefully in connection with evaluating us and this Annual Report on Form 10-K. Certain statements in "Risk Factor" are forward-looking statements. See "Cautionary Note Regarding Forward-Looking Statements" elsewhere in the report:

Risks Related to the Company's Business and Operation

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

Our financial performance depends on the successful operation of our geothermal and REG power plants. In connection with such operations, we derived 72.4% of our total revenues for the year ended December 31, 2019 from the sale of electricity. The cost of operation and maintenance and the operating performance of our geothermal power and REG plants may be adversely affected by a variety of factors, including the following:

- regular and unexpected maintenance and replacement expenditures;
- shutdowns due to the breakdown or failure of our equipment or the equipment of the transmission serving utility;
- labor disputes;
- the presence of hazardous materials on our power plant sites;
- continued availability of cooling water supply;
- catastrophic events such as fires, explosions, earthquakes, volcanic activity, landslides, floods, releases of hazardous materials, severe weather storms or other weather events (including weather conditions associated with climate change), or similar occurrences affecting our power plants or any of the power purchasers or other third parties providing services to our power plants, such as the recent volcanic eruption that occurred in Hawaii's Big Island that impacted our Puna project, as discussed elsewhere in this Report;
- the aging of power plants (which may reduce their availability and increase the cost of their maintenance); and
- cyber attacks that may interrupt the operation of our power plants.

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 flows.

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

Our primary business involves the exploration, development, and operation of geothermal energy resources. These activities are subject to uncertainties that, in certain respects, are similar to those typically associated with oil and gas exploration, development, and exploitation, such as dry holes, uncontrolled releases, and pressure and temperature decline. Any of these uncertainties may increase our capital expenditures and our operating costs or reduce the efficiency of our power plants. We may not find geothermal resources capable of supporting a commercially viable power plant at exploration sites where we have conducted tests, acquired land rights, and drilled test wells, which would adversely affect our development of geothermal power plants. Further, since the commencement of their operations, several of our power plants have experienced geothermal resource cooling, uncontrolled flow and/or reservoir pressure decline in the normal course of operations. 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. 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. A recent example is the Sarulla complex, which experienced a reduction in generation due to well field issues at the NIL power plant. The Sarulla complex is currently developing a remediation plan with a target to increase generation back to previous levels and we are following the remediation plans as well as assessing the accounting impact and its implication on our financial statements and our investment in the Sarulla complex.

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

On May 3, 2018, the Kilauea volcano located in close proximity to our Puna 38 MW geothermal power plant in the Puna district of Hawaii's Big Island erupted following a significant increase in seismic activity in the area. Before it recently stopped flowing, the lava covered the wellheads of three geothermal wells, monitoring wells and the substation of the Puna complex and an adjacent warehouse that stored a drilling rig that was also consumed by the lava. Certain of the insurance companies disputed the start date for business interruption insurance coverage and we have filed a lawsuit against such insurers. We continue to coordinate with HELCO and local authorities to bring the power plant back to operation. Further details on the status of the power plant is described under "Recent Development" below. The Company continues to assess the accounting implications of this event on the assets and liabilities on its balance sheet and whether an impairment will be required. We currently expect commercial operation of the full generating capacity in the third quarter of 2020; however, this is dependent on receipt of permits, completion of the transmission network upgrade and successful field recovery. Our failure to achieve commercial operation on that timeline would adversely impact our results of operations.

In addition to our power plant in Puna, Hawaii, our power plant in Amatitlan, Guatemala is located in proximity to an active volcano. As a result of recent events impacting our Puna facility, we cannot be certain how investors will assess the risks to which our facilities are subject and whether this assessment will adversely impact perceptions of our business and our share price.

Furthermore, absent additional geologic/hydrologic studies, any increase in power generation from our geothermal power plants, failure to reinject the geothermal fluid or improper maintenance of the hydrological balance may affect the

operational duration of the geothermal resource and cause it to decline in value over time and may adversely affect our ability to generate power from the relevant power plant.

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

We are implementing a multi-year strategic plan to:

- strengthen our core geothermal business in the United States as well as globally;
- establishing market position in the energy storage market; and
- exploring opportunities in new areas by looking for synergistic growth opportunities utilizing our core competence, market reputation as a successful company and new market opportunities focused upon environmental solution.

There are uncertainties and risks associated with our strategic plan, including with respect to implementation and outcome. We may decide to change, or to not implement, one or more elements of the plan over time or we may not be successful in implementing one or more elements of the plan, in each case for a number of reasons. For example, we may face significant challenges and risks expanding into the energy storage market (or expanding our core geothermal business), including:

- our ability to compete with the large number of other companies pursuing similar business opportunities in energy storage and solar PV power generation, many of which already have established businesses in these areas and/or have greater financial, strategic, technological or other resources than we have;
- our ability to obtain financing on terms we consider acceptable, or at all, which we may need, for example, to obtain any technology, personnel, intellectual property, or to acquire one or more existing businesses as a platform for our expansion, or to fund internal research and development, for energy storage and solar PV electric power generation products and services;
- our ability to provide energy storage or solar power generation products or services that keep pace with rapidly changing technology, customer preferences, equipment costs, market conditions and other factors that are unknown to us now that will impact these markets;
- Our ability to manage the risks and uncertainties associated with our operating storage facilities and future development of storage and geothermal projects which operate as "merchant" facilities without long-term sales agreements, including the variability of revenues and profitability of such projects;
- our ability to devote the amount of management time and other resources required to implement this plan, while continuing to grow our core geothermal and recovered energy businesses; and
- our ability to recruit appropriate employees.

Strengthening our core geothermal business to new customers and geographical areas will have many of the same risks and uncertainties as those outlined above.

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

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

These costs may not be recovered, in whole or in part, if one or more elements of the plan are not successfully implemented. These costs, or the failure to implement successfully one or more elements of the plan, could adversely affect our reputation and the reputation of our subsidiaries and could materially and adversely affect our business, financial condition, future results and cash flow.

Apart from the risks associated with implementing the plan, the plan itself will expose us to other risks and uncertainties once implemented. Expanding our customer base may expose us to customers with different credit profiles than our current customers. Expanding our geographic base will subject us to risks associated with doing business in new foreign countries in which we will have to learn the business and political environment. In addition, expanding into new technologies will expose us to new risks and uncertainties that are unknown to us now in addition to the risks and uncertainties that may be similar to those we now face. The success of the plan, once implemented, will depend, among other things, on our ability to manage these risks effectively.

The trading price of our common stock could decline if securities, industry analysts or our investors disagree with our strategic plan or the way we implement it accordingly, there is no assurance that the plan will enhance shareholder value through long-term growth of the Company to the extent currently anticipated by our management or at all.

Concentration of customers and regions may expose us to heightened financial exposure.

Our businesses often rely on a single customer to purchase all or a significant portion of a facility's output. The financial performance of these facilities depends on such customer continuing to perform its obligations under a long-term agreement between the parties. A facility's financial results could be materially and adversely affected if any of our customers fail to fulfill its contractual obligations and we are unable to find other customers to purchase at the same level of profitability. We cannot assure that such performance failures by our customers will not occur, or that if they do occur, such failures will not adversely affect the cash flows or profitability of our businesses.

For example, in the Electricity segment, we are exposed to the credit and financial condition of KPLC that buy the power generated from our Olkaria III in Kenya. In 2019, KPLC accounted for 16.3% of our total revenues. There has been a deterioration in the collection from KPLC that became slower than in the past, and as of December 31, 2019, the amount overdue from KPLC in Kenya was $40.7 million of which $24.2 million was paid in January and February of 2020. Any change in KPLC's financial condition may adversely affect us. Another example, we are exposed to the credit and financial condition of SCPPA and its municipal utility members that account for 17.9% of our total revenues, as customers that buy the output from seven of our geothermal power plants. Because our contracts with SCPPA are long-term, we may be adversely affected if the credit quality of any of these customers were to decline or if their respective financial conditions were to deteriorate or if they are otherwise unable to perform their obligations under our long-term contracts.

Another example, we are exposed to the credit and financial condition of ENEE in Honduras, which accounted for 4.6% of our total revenues in 2019. As of December 31, 2019, ENEE has an overdue amount of $20.1 million for the periods between October 2018 to April 2019, that was not paid to date. Due to obligations of the Honduran government to support our Company, we believe we will be able to collect all past due amounts, and therefore no provision for doubtful accounts has been recorded.

In the Product segment, 11.9% and 46.6%of our 2019 total revenues and Products segment revenue, respectively, were derived from our operations in Turkey and we rely on the continued geothermal development growth and government support for geothermal development in the country. Our revenue exposure to the Turkish market was significant in 2019 and we expect it to be reduced in 2020, due to slowdown in project development in the Turkish market. Adverse political developments in the relationship between Turkey and the U.S., adverse economic developments in this region including the 2018 failed coup, devaluation of the Turkish Lira, a general slowdown in the Turkish economy and an inability to obtain project and bank financing or a decline in government support for the development of geothermal power in the country could materially and adversely affect regional demand for the geothermal equipment and services we provide in the Turkish market or the prices we may charge for such equipment and services, which in turn could materially and adversely affect our Product segment profit margins and, consequently, our business, financial condition, future results and cash flows.

Ormat established a facility in Turkey in order to locally produce several power plant components that entitle our customer for increased incentives under the renewable energy laws. The use of local equipment in renewable energy based generating facilities in Turkey entitles such facilities to significant benefits under Turkish law, provided such facilities have obtained an RER Certificate from EMRA, which requires the issuance of a local certificate. If we do not obtain the local certificate, then some of our customers under the relevant supply agreements in Turkey may not be issued a RER Certificate based on the equipment we supply to them, and we will be required to make a payment to such customers equal to the amount of the expected lost benefit

Our international operations expose us to risks related to the application of foreign laws and regulations, any of which may adversely affect our business, financial condition, future results and cash flows.

Our foreign operations in Kenya, Turkey, Guadeloupe, Guatemala, Honduras and other countries are subject to regulation by various foreign governments and regulatory authorities and are subject to the application of foreign laws. Such foreign laws or regulations may not provide the same type of legal certainty and rights, in connection with our contractual relationships in such countries, as are afforded to our operations in the United States, which may adversely affect our ability to receive revenues or enforce our rights in connection with our foreign operations. The systems of some of these countries can be characterized by:

- selective or inconsistent enforcement of laws or regulations, sometimes in ways that have been perceived as being motivated by political or financial considerations;
- a perceived lack of judicial and prosecutorial independence from political, social and commercial forces;
- a high degree of discretion on the part of the judiciary and governmental authorities;
- legal and bureaucratic obstacles and corruption; and
- rapid evolution of legal systems in ways that may not always coincide with market developments.

These characteristics give rise to investment risks that do not exist in countries with more established legal systems in more developed economies.

We face additional risks inherent in conducting business internationally, including compliance with laws and regulations of many jurisdictions that apply to our international operations. These laws and regulations include data privacy requirements, labor relations laws, tax laws, competition regulations, import and trade restrictions, economic sanctions, export requirements, the Foreign Corrupt Practices Act, and other local laws that prohibit corrupt payments to governmental officials or certain payments or remunerations to customers. Given the high level of complexity of these laws, there is a risk that some provisions may be breached by us, for example through fraudulent or negligent behavior of individual employees (or third parties acting on our behalf), our failure to comply with certain formal documentation requirements, or otherwise. Violations of these laws and regulations could result in fines, criminal sanctions against us, our officers or our employees, requirements to obtain export licenses, cessation of business activities in sanctioned countries, implementation of compliance programs and prohibitions on the conduct of our business. Any such violation could include prohibitions on our ability to offer our products in one or more countries and could materially damage our reputation, our brand, our ability to attract and retain employees, our business, our financial condition and our results of operations.

Furthermore, existing laws or regulations may be amended or repealed, and new laws or regulations may be enacted or issued. In addition, the laws and regulations of some countries may limit our ability to hold a majority interest in some of the power plants that we may develop or acquire, thus limiting our ability to control the development, construction and operation of such power plants, or our ability to import our products into such countries.

Political, economic and other conditions in the emerging economies where we operate may subject us to greater risk than in the developed U.S. economy, which may have a materially adverse effect on our business.

We have substantial operations outside of the United States, both in our Electricity segment and our Product segment. In 2019, 49.3% of our total revenues were derived from international operations, and our international operations were significantly more profitable than our U.S. operations. A substantial portion of international revenues came from Kenya and Turkey and, to a lesser extent, from Honduras, Guatemala, Guadeloupe and other countries. Thus, disturbances to and challenges facing our foreign operations, especially in Kenya and Turkey, could have impacts on our business ranging from moderate to severe. Our foreign operations subject us 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;
- the adoption or expansion of trade restrictions, the occurrence or escalation of a "trade war," or other governmental action related to tariffs or trade agreements or policies among the governments of the United States and countries where we operate;
- reduced protection for intellectual property rights in some countries;
- changes in labor relations;
- political instability and civil unrest, and risk of war;
- changes in the local electricity and/or geothermal markets;
- difficulties enforcing our rights against a governmental agency because of the doctrine of sovereign immunity and foreign sovereignty over international operations;
- breach or repudiation of important contractual undertakings by governmental entities; and
- expropriation and confiscation of assets and facilities, including without adequate compensation.

Electricity Segment. In 2019, the international operations of the Electricity segment accounted for 28% of our total revenues, but accounted for 52% of our gross profit, 59% of our net income and 48% of our EBITDA. A substantial portion of Electricity segment international revenues came from Kenya (which also contributed disproportionately to our gross profit and net income) and, to a lesser extent, from Guadeloupe, Guatemala and Honduras. In Kenya, any break-up or potential privatization of KPLC, the power purchase for our power plants located in Kenya, may adversely affect our Olkaria III complex and our overall results of operations. Additionally, 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.

Product Segment. With respect to our Product segment, 84% of our Product segment revenues in 2019 came from international sales, primarily Turkey. Since we primarily engage in sales in those markets where there is a geothermal reservoir, any such change might adversely affect geothermal developers in those markets and, subsequently, the ability of such developers to purchase our products.

Generally. Outbreaks of civil and political unrest and acts of terrorism have also occurred in several countries in Africa, the Middle East and Latin America, where we have significant operations, such as Kenya and Turkey. For instance, Kenya experienced numerous terrorist attacks in 2014 and 2015, and has experienced an upsurge in attacks in more recent years, including in early 2019, from extremist groups. Continued or escalated civil and political unrest and acts of terrorism in the countries in which we operate could result in our curtailing operations. In the event that countries in which we operate experience civil or political unrest or acts of terrorism, especially in events where such unrest leads to an unseating of the established government, our operations in such countries could be materially impaired. 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. Any or all of the changes discussed above could materially and adversely affect our business, financial condition, future results and cash flow.

Two of our facilities accounts for 29% of our revenues and contribute significantly to our profitability.

Our business relies significantly on the performance of our two largest projects, the McGinness Hills complex in East Nevada and Olkaria III Complex in Kenya, which together accounted for more than 30% of the total generating capacity of our Electricity segment in 2019. These two facilities accounted for 29% of our total revenues for the year ended December 31, 2019. Any disruption to the operation of these facilities would have a disproportionately adverse effect on our revenues and on our profitability.

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

The majority of our senior management and our main production and manufacturing facilities are located in Israel approximately 26 miles from the border with the Gaza Strip. As such, political, economic and security conditions in Israel directly affect our operations.

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

In addition, some of our employees in Israel are subject to being called upon to perform military service in Israel, and their absence may have an adverse effect upon our operations.

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

We have significant operations globally, including in countries that may be adversely affected by political or economic instability, major hostilities or acts of terrorism, which exposes us to risks and challenges associated with conducting business internationally.

We have substantial operations outside of the U.S., both in our Electricity segment and our Product segment. 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.

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 (approximately 293,000 acres in the U.S. and approximately 15,000 acres elsewhere) 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, may terminate. In the event that a lease is terminated and we determine that we will need that lease once the applicable power plant is operating, we would need to enter into one or more new leases with the owner(s) of the premises that are the subject of the terminated lease(s) in order to develop geothermal resources from, or inject geothermal resources into, such premises or secure rights to alternate geothermal resources or lands suitable for injection. We may not be able to do this or may not be

able to do so without incurring increased costs, which could materially and adversely affect our business, financial condition, future results and cash flow.

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

Pursuant to the terms of our BLM leases, we are required to conduct our operations on BLM-leased land in a workmanlike manner and in accordance with all applicable laws and BLM directives and to take all mitigating actions required by the BLM to protect the surface of and the environment surrounding the relevant land. Additionally, certain BLM leases contain additional requirements, some of which relate to the mitigation or avoidance of disturbance of any antiquities, cultural values or threatened or endangered plant, wildlife and species. 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.

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

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

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

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

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

- inability to secure a PPA;
- inability to secure transmission services agreements;
- inability to secure the required financing;
- cost increases and delays due to unanticipated shortages of adequate resources to execute the project such as equipment, material and labor;
- work stoppages resulting from force majeure event including riots, strikes and whether conditions;
- inability to obtain permits, licenses and other regulatory approvals;
- failure to secure sufficient land positions for the wellfield, power plant and rights of way;
- failure by key contractors and vendors to timely and properly perform, including where we use equipment manufactured by others;
- inability to secure or delays in securing the required transmission line and/or capacity;
- adverse environmental and geological conditions (including inclement weather conditions);
- adverse local business law;
- our attention to other projects and activities, including those in the solar energy and energy storage sectors; and
- changes in laws that mandate, incentivize or otherwise favor renewable energy sources.

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

Our future growth depends, in part, on the successful enhancement of a number of our existing facilities.

Our current growth plans include enhancement and repowering of a number of our operating facilities, including the Heber, Steamboat, Ormesa, Mammoth and Puna complexes and involve replacement of old equipment and optimization of the geothermal field, including repair and enhancement of existing wells and drilling of new wells. Such enhancement and repowering are subject to geological risks and uncertainties and satisfactory completion of field development, testing, permitting and power plant construction and commissioning, which may result in delays and cost overruns.

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, of if there is a failure that requires long shutdown for repair, or if curtailment is required due to load system inefficiency, 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.

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

We have partners in several of our plants and we may continue in the future to develop and/or acquire and/or hold properties in joint ventures with other entities when circumstances warrant the use of these structures. Ownership of assets in joint ventures is subject to risks that may not be present with other methods of ownership, including:

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

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

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

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

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

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

Our operations could be adversely impacted by climate change.

Daily and seasonal fluctuations in temperature generally have a more significant impact on the generating capacity of geothermal energy plants than conventional power plants. Some of our power plants experience reduced generation in warm periods due to the lower heat differential between geothermal fluid and the ambient surroundings. While we generally account for the projected impact seasonal fluctuations in temperature based on our historic experience, the impact of climate change on traditional weather patterns has become more pronounced. This has reduced the certainty of our modelling efforts. For example, in 2019, we experienced prolonged elevated temperatures in the Western United States which impacted generating capacity at our facilities and adversely impacted our revenues in the fourth quarter of the year. To the extent weather conditions continue to be impacted by climate change, the generating capacity of certain of our facilities may be adversely impacted in a manner that we could not predict which may in turn adversely impact our results of operations.

Geothermal projects that we plan to develop in the future, may operate as "merchant" facilities without long-term PPAs and therefore such projects will be exposed to market fluctuations.

Geothermal projects that we plan to develop in the United States as part of our growth plans may operate as "merchant" facilities and sell electricity without long-term PPAs for some or all of their generating capacity and output. Such projects are exposed to market fluctuations. Without the benefit of long-term PPAs for these assets, we cannot be sure that we will be able to sell any or all of the power generated by these facilities at commercially attractive rates or that these facilities will be able to operate profitably. This could lead to future impairments of our property, plant and equipment resulting in economic losses and liabilities, which could have a material adverse effect on our results of operations, financial condition or cash flows.

Storage projects that we are operating, currently developing or plan to develop in the future, may operate as "merchant" facilities without long-term power services agreements for some or all of their generating capacity and output and therefore such projects will be exposed to market fluctuations.

Storage projects that we own and operate, are currently developing or plan to develop in the future, may operate as "merchant" facilities without long-term sales agreements for some or all of their generating capacity and output and therefore such projects are exposed to market fluctuations. Without the benefit of long-term services agreements for these assets, we cannot be sure that we will be able to sell any or all of the power and ancillary services provided by these facilities at commercially attractive rates or that these facilities will be able to operate profitably. This could lead to future impairments of our property, plant and equipment or to the closing of certain of our storage facilities, resulting in economic losses and liabilities, which could have a material adverse effect on our results of operations, financial condition or cash flows.

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

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

- failure of the acquired companies to achieve the results we expect;
- inability to retain key personnel of the acquired companies;
- risks associated with unanticipated events or liabilities; and
- the difficulty of establishing and maintaining uniform standards, controls, procedures and policies, including accounting controls and procedures.

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

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

The power generation industry is characterized by intense competition from electric utilities, other power producers and power marketers. In recent years, there has been increasing competition in the sale of electricity, in part due to excess capacity in a number of United States 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 and/or renew long-term PPAs and the price paid for electricity by the relevant power purchasers. There is also increasing competition between electric utilities. This competition has put pressure on electric utilities to lower their costs, including the cost of purchased electricity, and increasing competition in the future will put further pressure on power purchasers to reduce the prices at which they purchase electricity from us.

We face increasing competition from other companies engaged in the solar, energy storage, demand response and energy management sectors.

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 panels, silicon wafers, and other related products for the solar industry, which may give them an advantage in developing, constructing, owning and operating solar power projects. Our limited experience in the solar PV sector may affect our ability to successfully develop, construct, finance, and operate solar PV power projects.

We are experiencing intense competition in the energy storage, demand response and energy management markets. Our competitors in the energy storage, demand response and energy management markets include utilities, independent power producers, developers, new start-ups, and third-party investors, who compete more successfully in these markets than our Viridity business. If we are unable, as a result of increased competition, to expand our customer base or increase our market share in these rapidly growing markets, our business, financial condition, future results and cash flow could be materially and adversely affected.

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 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 such as hydroelectric systems, fuel cells, microturbines, wind turbines, energy storage systems and solar PV systems. Some of these alternative technologies currently produce electricity at higher average prices than our

geothermal plants while others produce electricity at lower average prices. It is possible that technological advances and economies of scale will further reduce the cost of alternate methods of power generation. It is also possible that energy technologies will compete with our basic premise of a firm (non-intermittent) renewable baseload power source by combining renewable technologies with energy storage to provide an alternative to firm baseload energy. If this were to happen, the competitive advantage of our power plants may be significantly impaired.

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

Our existing intellectual property rights, including those we acquired in connection with the acquisition of our Viridity business, may not be adequate to protect our business. While we occasionally file patent applications. However, the patent prosecution process is expensive, time-consuming and complex and we may not be able to prepare, file, prosecute, maintain and enforce all necessary or desirable patent applications at a reasonable cost or in a timely manner. Patents may be invalidated and patents may not be issued on the basis of suchour patent applications or, if. Additionally, the scope of patent protection can be reinterpreted after issuance. Even if our patent applications do issue as patents are issued, they may not beissue in a form that is sufficiently broad to protect our technology, prevent competitors or other third parties from competing with us or otherwise provide us with any competitive advantage. In addition, any patents issued to us or for which we have use rights may be challenged, narrowed, invalidated or circumvented. Third parties may initiate opposition, interference, re-examination, post-grant review, inter partes review, nullification or derivation actions, or similar proceedings challenging the inventorship, validity, enforceability or scope of our patents. An adverse determination in any such proceeding or litigation could reduce the scope of, or invalidate our patent rights, allow third parties to commercialize our technology and compete directly with us, without payment to us, or result in our inability to commercialize our technology without infringing third-party patent rights. Such proceedings also may result in substantial cost and require significant time from our management, even if the eventual outcome is favorable to us. Our competitors or other third parties may also be able to circumvent our patents by developing similar or alternative technologies in a non-infringing manner. Consequently, we do not know whether any of our technology will be protectable or remain protected by valid and enforceable patents.

In order to safeguard our unpatented proprietary know-how, trade secrets and technology, we rely on a combination of trade secret protection and non-disclosure provisions in agreements with employees and third parties having access to confidential or proprietary information. These measures may not adequately protect us from disclosure, use, reverse engineering, infringement, misappropriation or other violation of our proprietary information and other intellectual property rights by third parties. Furthermore, non-disclosure provisions can be difficult to enforce and, even if successfully enforced, may not be entirely effective. In addition, we cannot guarantee that we have entered into non-disclosure agreements with all employees and third parties that have or may have had access to our trade secrets and other confidential or 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. Furthermore, attempts to enforce our intellectual property rights against third parties could also provoke these third parties to assert their own intellectual property or other rights against us, or result in a holding that invalidates or narrows the scope of our rights, in whole or in part. Our success and ability to compete also depends in part on our ability to operate without infringing, misappropriating or otherwise violating the intellectual or proprietary rights of third parties. While we have attempted to ensure that our technology and the operation of our business does not infringe other parties' patents and other intellectual property or proprietary rights, our competitors or other third parties may assert that certain aspects of our business or technology infringe upon, misappropriate or otherwise violate their intellectual property or proprietary rights. In addition, former employers of our current, former or future employees may assert claims that such employees have improperly disclosed to us the confidential or proprietary information of these former employers. Infringement, misappropriation or other intellectual property violation claims, regardless of merit or ultimate outcome, can be expensive, hard to predict and time-consuming and can divert management's attention from our core business. An assertion of an intellectual property infringement, misappropriation or other violation claim against us may result in adverse judgments, settlements on unfavorable terms or cause us to pay significant money damages, lose significant revenues, be prohibited from using the relevant technology or other intellectual property, or incur significant license, royalty or technology development expenses. Future litigation may also involve non-practicing entities or other intellectual property owners who have no relevant product offerings or revenue and against whom our own intellectual property may therefore provide little or no deterrence or protection.

We may experience difficulties implementing and maintaining our new enterprise resource planning system

We purchased a new enterprise resource planning ("ERP") system and are currently in the initial phases of implementing the new system. ERP implementations are complex and time-consuming, and involve substantial expenditures on system software and implementation activities. The ERP system will be critical to our ability to provide important information to our management, obtain and deliver products, provide services and customer support, send invoices and track

payments, fulfill contractual obligations, accurately maintain books and records, provide accurate, timely and reliable reports on our financial and operating results or otherwise operate our business. ERP implementations also require transformation of business and financial processes in order to reap the benefits of the ERP system; any such transformation involves risks inherent in the conversion to a new computer system, including loss of information and potential disruption to our normal operations. The implementation and maintenance of the new ERP system has required, and will continue to require, the investment of significant financial and human resources and the implementation may be subject to delays and cost overruns. In addition, we may not be able to successfully complete the implementation of the new ERP system without experiencing difficulties. Any disruptions, delays or deficiencies in the design and implementation or the ongoing maintenance of the new ERP system could adversely affect our ability to process orders, ship products, provide services and customer support, send invoices and track payments, fulfill contractual obligations, accurately maintain books and records, provide accurate, timely and reliable reports on our financial and operating results, or otherwise operate our business. Additionally, if we do not effectively implement the ERP system as planned or the system does not operate as intended, the effectiveness of our internal control over financial reporting could be adversely affected or our ability to assess it adequately could be delayed.

A cyber incident, cyber security breach, severe natural event or physical attack on our operational networks and information technology systems could have a material adverse effect on our financial condition, results of operations, liquidity and cash flows.

We rely on information technology systems that allow us to create, store, retain, transmit and otherwise process proprietary and sensitive or confidential information, including our business and financial information, and personal information regarding our employees and third-parties. We also rely on our operational technology systems to manufacture equipment for our energy projects, operate our power plants and provide our services. In addition, we often rely on third-party vendors to host, maintain, modify and update our systems.

Our and our third-party vendors' technology systems can be damaged by malicious events such as cyber and physical attacks, computer viruses, malicious and destructive code, phishing attacks, denial of service or information, as well as security breaches, natural disasters, fire, power loss, telecommunications failures, employee misconduct, human error, and third parties such as traditional computer hackers, persons involved with organized crime or foreign state or foreign state-supported actors. Furthermore, our disaster recovery planning may not be sufficient for all situations. Any failure, disruptions to or decrease in the functionality of our or our third-party vendors' operational and information technology networks could impact our ability to maintain effective internal controls over financial reporting, cause harm to the environment, the public or our employees, and significantly disrupt and damage our assets and operations or those of third parties.

We and our third-party vendors have been, and may in the future be, subject to breaches and attempts to gain unauthorized access to our information technology systems or sensitive or confidential data, or to disrupt our operations. To date, none of these breaches or attempts has, individually or in the aggregate, resulted in a security incident with a material effect on our operations or our financial condition, results of operations, liquidity, or cash flows. Despite implementation of security and control measures, we and our third-party vendors have not always been able to, and there can be no assurance that we or our third-party vendors will be able to in the future, anticipate or prevent unauthorized access to our or our third-party vendors' operational technology networks, information technology systems or data, or the disruption of our or our third-partv vendors' operations. The techniques used to obtain unauthorized access to our and our third-party vendors' operational technology networks, information technology systems or data are constantly evolving and have become increasingly complex and sophisticated. Furthermore, such techniques change frequently and are often not detected until after they have been launched against a target. Therefore, we may be unable to anticipate these techniques and may not become aware in a timely manner of such a security breach, which could exacerbate any damage we experience. Such events could cause interruptions in the operation of our business, damage our operational technology networks and information technology systems, subject us to significant expenses, remediation costs, litigation, disputes, claims by third parties and regulatory actions or investigations that could result in damages, material fines and penalties, and harm to our reputation, any of which could have a material adverse effect on our financial condition, results of operations, liquidity, and cash flows. We may maintain cyber liability insurance that covers certain damages caused by cyber incidents. However, there is no guarantee that adequate insurance will continue to be available at rates that we believe are reasonable or that the costs of responding to and recovering from a cyber incident will be covered by insurance or recoverable in rates.

In addition, we are subject to various legislation, regulations, directives and guidelines from federal, state, local and foreign agencies, such as FERC, that are intended to strengthen cybersecurity measures required for information and operational technology and critical energy infrastructure and that apply to the collection, use, retention, protection, disclosure, transfer and other processing of personal information. These cybersecurity, data protection and privacy law regimes continue to evolve and may result in ever-increasing public scrutiny and escalating levels of capital expenditures, regulatory enforcement, sanctions and fines and increased costs for compliance. Failure to comply with any of these laws could result in enforcement action against us, including fines, imprisonment of company officials and public censure, any of which could

harm our reputation and have a material adverse effect on our financial condition, results of operations, liquidity, and cash flows.

We previously identified a material weakness in our internal control over financial reporting and subsequently restated certain of our financial statements as a result of factors related to that weakness. This may adversely affect the accuracy and reliability of our financial statements and impact our reputation, business and the price of our common stock, as well as lead to a loss of investor confidence in us.

In connection with the change in our repatriation strategy and the related release of the U.S. income tax valuation allowance in the second quarter of 2017, we did not perform an effective risk assessment related to our internal controls over the accounting for income taxes. As a result, we identified a deficiency in the design of our internal control over financial reporting related to our accounting for income taxes, which affected the recording of income tax accounts by us in our interim and annual consolidated financial statements during 2017. Our management previously concluded that this deficiency constituted a material weakness in our internal control over financial reporting and, accordingly, our internal control over financial reporting and our disclosure controls and procedures were not effective as of December 31, 2017. A material weakness is a deficiency, or a combination of deficiencies, in internal control over financial reporting, such that there is a reasonable possibility that a material misstatement of our annual or interim consolidated financial statements will not be prevented or detected on a timely basis.

On May 16, 2018, we concluded that we would restate our previously issued consolidated financial statements as of and for the year ended December 31, 2017 to correct for (i) errors in our income tax provision, primarily related to our ability to utilize foreign tax credits in the United States prior to their expiration starting in 2027 and the resulting impact on the deferred tax asset valuation allowance, and (ii) the inappropriate netting of certain deferred income tax assets and deferred income tax liabilities across different tax jurisdictions that was not permissible under U.S. generally accepted accounting principles. In addition, we also concluded that we would revise our previously issued consolidated financial statements as of and for the years ended December 31, 2016 and December 31, 2015 to correct for errors in our income tax provision primarily related to the translation of deferred tax liabilities in a foreign subsidiary. These tax and tax-related errors also resulted in the restatement, for 2017, and revision, for 2016, of our previously issued unaudited condensed consolidated financial statements for the three months ended March 31, 2017, for the three and six months ended June 30, 2017 and 2016 and for the three and nine months ended September 30, 2017 and 2016.

We have made substantial progress in developing and implementing a remediation plan, as we are adding to and improving our internal processes. However, the material weakness will not be considered remediated until the applicable controls operate for a sufficient period of time and management has concluded, through testing, that these controls are operating effectively. As such, we have determined that we did not maintain an effective internal control over financial reporting as of December 31, 2019 and have a material weakness in internal control over financial reporting in accounting for income taxes. If we are unable to remediate this material weakness or we identify additional material weaknesses in our internal control over financial reporting in the future, our ability to analyze, record and report financial information accurately, to prepare our financial statements within the time periods specified by the rules and forms of the SEC and to otherwise comply with our reporting obligations under the federal securities laws, and in relation to covenants in certain debt facilities will likely be adversely affected. We may identify additional material weaknesses in our internal control over financial reporting in the future. The occurrence of, or failure to remediate, and any future material weaknesses in our internal control over financial reporting may adversely affect the accuracy and reliability of our financial statements, and our reputation, business and the price of our common stock or any other securities we may issue, as well as lead to a loss of investor confidence in us.

Risks Related to Governmental Regulations, Laws and Taxation

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

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 energy regulation currently is, and may continue to be, subject to challenges, modifications, the imposition of additional regulatory requirements, and restructuring proposals. We or our power purchasers may not be able to obtain all regulatory approvals that may be required in the future, or any necessary modifications to existing regulatory approvals, or maintain all required regulatory approvals. In addition, the cost of operation and maintenance and the operating performance of geothermal power plants may be adversely affected by changes in certain laws and regulations, including tax laws.

Any changes to applicable laws and regulations or interpretations of those laws and regulations could significantly increase the regulatory-related compliance, tax 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. A recent example is the assessment letters we received from the KRA with respect to our operation in Kenya in relation to the 2013 to 2017 tax years in which the KRA demanded we pay approximately $228.0 million including interest and penalties ($177.0 million principal). We are currently at different stages of discussions with the KRA on the matters included in their letters of assessment and preliminary findings and believe our tax positions for the issues raised during the audit are sustainable based on technical merits under Kenyan tax law.

SEC rules related to conflict minerals require that we disclose the use of "conflict minerals" (including tantalum, tin, tungsten and gold) in our products. Such disclosure may force us to incur additional expenses and may damage our relationships with customers. If we utilize any of these minerals and they are necessary to the production or functionality of any of our products, we will need to conduct specified due diligence activities and file with the SEC a report disclosing, among other things, whether such minerals originate from the Democratic Republic of Congo or adjoining countries. The implementation of these SEC rules could adversely affect the sourcing, availability, and pricing of minerals used in the manufacture of certain components incorporated in our products. In addition, we expect to incur additional costs to comply with the disclosure requirements. Because our supply chain is complex, we may not be able to verify the origins of all of the minerals and metals used in our products through the diligence procedures, thus risking reputational harm. The inability to verify the origins of all mineral and metals may also create difficulties in satisfying customers who require that all of the components of our products are certified as conflict mineral free.

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

Pursuant to the terms of certain of our PPAs, we may be required to make payments to the relevant power purchaser under certain conditions, such as shortfall in delivery of renewable energy and energy credits, and not meeting certain performance threshold requirements, as defined in the relevant PPA. The amount of payment required is dependent upon the level of shortfall in delivery or performance requirements and is recorded in the period the shortfall occurs. In addition, if we do not meet certain minimum performance requirements, the capacity of the relevant power plant may be permanently reduced. Any or all of these considerations could materially and adversely affect our business, financial condition, future results and cash flow.

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

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

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

If a domestic power plant were to lose its Qualifying Facility status, it would become subject to full regulation as a public utility under the FPA, and the rates charged by such power plant pursuant to its PPAs may be subject to the review and approval of FERC. FERC, upon such review, may determine that the rates currently set forth in such PPAs are not appropriate and may set rates that are lower than the rates currently charged. In addition, FERC may require that the affected domestic power plant refund amounts previously paid by the relevant power purchaser to such power plant. Even if a power plant does not lose its Qualifying Facility status, pursuant to regulations issued by FERC for Qualifying Facility power plants above 20 MW, if a power plant's PPA is terminated or otherwise expires, and the subsequent sales are not made pursuant to a state's implementation of PURPA, that power plant will become subject to FERC's ratemaking jurisdiction under the FPA. Moreover, a loss of Qualifying Facility status also could permit the power purchaser, pursuant to the terms of the particular PPA, to cease taking and paying for electricity from the relevant power plant or, consistent with FERC precedent, to seek refunds of past amounts paid. This could cause the loss of some or all of our revenues payable pursuant to the related PPAs, result in significant liability for refunds of past amounts paid, or otherwise impair the value of our power plants. If a power purchaser were to cease taking and paying for electricity or seek to obtain refunds of past amounts paid, there can be no

assurance that the costs incurred in connection with the power plant could be recovered through sales to other purchasers or that we would have sufficient funds to make such payments. In addition, the loss of Qualifying Facility status would be an event of default under the financing arrangements currently in place for some of our power plants, which would enable the lenders to exercise their remedies and enforce the liens on the relevant power plant.

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

The PURPA and QF described risks identified above are not likely to affect our Nevada based facilities that entered into PPAs with NV Energy as the off-taker after Nevada initially adopted its RPS in 2001. Those PPAs and the related rates agreed to for such facilities by the off-taker were not based upon PURPA or a QF mandated rate but were instead adopted as a result of a competitive bidding process and approved as part of the off-taker's integrated resource planning process and in order for the off-taker to comply with Nevada's RPS. While those PPAS were initially required to file for QF or EWG status with the FERC, the PPAs and their related prices for the term of the PPA were not approved by the FERC pursuant to PURPA. The PURPA and QF risks described above also are not likely to affect our Nevada and California based projects that have their PPAs with the SCPPA because SCPPA is not a regulated public utility under PURPA.

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

Construction and operation of our geothermal power plants and recovered energy-based power plants has benefited, and may benefit in the future, from public policies and government incentives that support renewable energy and enhance the economic feasibility of these projects in regions and countries where we operate. Such policies and incentives include PTCs (that are applicable for projects that begin construction by the end of 2020) and ITCs (for projects that begin construction by the end of 2021), accelerated depreciation tax benefits, renewable portfolio standards, carbon trading mechanisms, rebates, and mandated feed-in-tariffs, and may include similar or other incentives to end users, distributors, system integrators and manufacturers of geothermal, solar and other power products. Some of these measures have been implemented at the federal level, while others have been implemented by different states within the United States or countries outside the United States where we operate.In particular, the current U.S. presidential administration has made public statements that indicate that the administration may not be supportive of various clean energy programs and initiatives designed to curtail climate change, and has taken certain actions to eliminate or limit support for these programs and initiatives. For example, in June 2017, the administration announced that the United States would withdraw from participation in the 2015 Paris Agreement on climate change, which will become effective in November 2020. In addition, the administration has implemented and proposed policies supporting the exploration, production and use of fossil fuels and eliminating regulations enacted by the prior administration seeking to limit these activities.

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

We are a holding company and our cash depends substantially on the performance of our subsidiaries and the power plants they operate, most of which is 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 some 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. In all of the foreign countries where our existing power plants are located, dividend payments to us may also be subject to withholding taxes. Each of the events described above may reduce or eliminate the aggregate amount of cash we can receive from our subsidiaries.

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

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

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 generation, handling, transportation, use, storage, treatment and disposal of hazardous substances. We use butane, pentane, industrial lubricants, and other substances at our power plants which are or could become classified as hazardous substances. If any hazardous substances are found to have been released into the environment at or by the power plants in concentrations that exceed regulatory limits, we could become liable for the investigation and removal of those substances, regardless of their source and time of release. If we fail to comply with these laws, ordinances or regulations (or any change thereto), we could be subject to civil or criminal liability, the imposition of liens or fines, and cessation of operations, large expenditures to bring the power plants into compliance or other sanctions. Furthermore, under certain federal and states laws in the United States, we can be held liable for the cleanup of releases of hazardous substances at any of our current or former facilities or at any other locations where we arranged for disposal of those substances, even if we did not cause the release at that location or if the release complied with applicable law at the time it occurred. Liability under these laws can be joint and several. The cost of any remediation activities in connection with a spill or other release of such substances could be significant and could expose us to significant liability.

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

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

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

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

Possible application of the new base erosion and anti-abuse tax in the United States may adversely affect us.

The Tax Act enacted in 2017 in the United States included BEAT, that could apply to us and, more importantly, could reduce the amount of tax equity that can be raised on geothermal projects on which PTCs will be claimed. The aim of the base erosion and anti-abuse tax is to prevent multinational companies from reducing their U.S. taxes by "stripping" earnings across the U.S. border by making payments to foreign affiliates that can be deducted in the United States An example of such a payment is interest on an intercompany loan or a payment to a back office in a foreign country for equipment or services. The goal of the BEAT is to ensure that multinational companies do not use cross-border payments to reduce their U.S. taxes to less than 10% (12.5% for years beginning after December 31, 2025) of an expanded definition of taxable income. BEAT requires an annual calculation. Generally, the tax only applies to certain corporations with at least $500 million in average annual gross receipts for the United States for the three prior taxable years before the calculation and with base erosion payments that account for at least 3 percent (2 percent for certain corporations) of their deductions for the taxable year. If the tax applies to us, our tax equity raised on geothermal projects on which PTCs can be claimed may be reduced, which in turn may materially and adversely affect our business, financial condition, future results and cash flow.

Risks Related to Economic and Financial Conditions

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

Most of our geothermal power plants generally have been financed using leveraged financing structures, consisting of non-recourse or limited recourse debt obligations. Each of our projects under development or construction and those projects and businesses we may seek to acquire, or construct will require substantial capital investment. Our continued access to capital on 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 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, investor confidence, the continued success of current power plants, the credit quality of the power plants being financed, the political situation in the country where the power plant is located, and the continued existence of tax and securities laws which are conducive to raising capital. If we are not able to obtain financing for our power plants on a substantially non-recourse or limited recourse basis, we may have to finance them using recourse capital such as direct equity investments or the incurrence of additional debt by us.

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

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

Our 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 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.

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

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

project subsidiary or our project subsidiary owning the power plant would only retain an interest in the physical assets, if any, remaining after all debts and obligations were paid in full.

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

Our manufacturing operations are dependent on the supply of various raw materials, including primarily steel and aluminum, commodities and industrial equipment components that we use. We currently obtain all such raw materials, commodities and equipment at prevailing market prices. We are not dependent on any one supplier and do not have any long-term agreements with any of our suppliers. Global events such as the ongoing corona-virus outbreak emanating from China at the beginning of 2020 that has resulted in extended shutdown of certain businesses in the region and may result in delays in the supply of raw materials and components that we purchase for our equipment manufacturing may lead to cost increases. Future cost increases of such raw materials, commodities and equipment, to the extent not otherwise passed along to our customers, could adversely affect our profit margins.

Risks Related to Force Majeure

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

The operation of our subsidiaries' geothermal power plants is subject to a variety of risks discussed elsewhere in these risk factors, including events such as fires, explosions, earthquakes, landslides, floods, severe storms, volcanic eruptions, lava flow or other similar events. If a power plant experiences an occurrence resulting in a force majeure event, although our subsidiary that owns that power plant would be excused from its obligations under the relevant PPA the relevant power purchaser may not be required to make any capacity and/or energy payments with respect to the affected power plant for as 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, and if as a result the power plant fails to attain certain performance requirements under certain of our PPAs, the power 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.

Threats of terrorism, natural catastrophes or public health crises and other catastrophic events 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, natural disasters, public health crises, fire, power loss and telecommunication failures, as well as cyber-attacks, including, among others, malware, computer viruses and attachments to e-mails, phishing attacks, denial of service or information, remote interruption to the operation of our power plants and other disruptive activities of individuals or groups, including traditional computer hackers, persons involved with organized crime or foreign state or foreign state-supported actors. Our generation and transmission facilities, information technology systems and other infrastructure facilities, systems and physical assets, including our Viridity business's VPowerTM software platform, as well as the information technology systems of our third-party vendors, could be directly or indirectly affected by such events or activities.

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 and our third-party vendors' technology systems (and any programs or data stored thereon or therein) are vulnerable to security breaches, disruptions, 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. In addition, such events or activities could require significant management attention and resources and could adversely affect our reputation among customers and the public. The implementation of security guidelines and measures and maintenance of insurance, to the extent available, addressing such events or activities could significantly increase our costs. Furthermore, there is no guarantee that such security guidelines and measures will adequately anticipate or prevent such events or activities and our insurance may not cover any or all losses arising out of such events or activities.

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.

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

On December 22, 2017, U.S. federal tax legislation, commonly referred to as the Tax Act was signed into law, significantly reforming the U.S. Internal Revenue Code. The Tax Act, among other things, reduces the U.S. federal corporate tax rate from the previous top marginal rate of 35% to a flat rate of 21%, imposes significant additional limitations on the deductibility of interest, allows for the expensing of certain capital expenditures, puts into effect the migration from a "worldwide" system of taxation to a territorial system and modifies or repeals many business deductions and credits, including modifying the treatment of net operating losses.

Under the Tax Act, the deductibility of "net interest" for a business is limited to 30% of adjusted taxable income. The new proposed regulations issued by Treasury applies regardless of whether the interest payment is made to a U.S. or foreign person, whether the interest recipient is related, or whether the interest recipient is exempt from U.S. tax. Further, any interest that cannot be deducted in a year can be carried forward indefinitely. For the year ended December 31, 2019 we determined to adopt the proposed regulations in advance and determined that $28.3 million of interest expense cannot be deducted in the current year but can be carried forward indefinitely.

We continue to examine the impact the Tax Act may have on our business. Notwithstanding the reduction in the corporate income tax rate, the overall impact of the Tax Act is uncertain, and our business, financial condition, future results and cash flow, as well as our stock price, could be adversely affected.

Risks Related to Our Stock

A substantial percentage of our common stock is held by stockholders whose interests may conflict with the interests of our other stockholders.

On July 26, 2017, ORIX purchased approximately 22% of our shares of common stock outstanding. Pursuant to the Governance Agreement between us and ORIX entered into in connection with this stock purchase transaction, ORIX has the right to designate three directors to our Board for as long as ORIX and its affiliates collectively hold at least 18% of the voting power of all of our outstanding voting securities, the right to representation on certain committees of our Board as well as preemptive rights pursuant to the Governance Agreement. In addition, the Governance Agreement provides ORIX preemptive rights in the event we issue common stock or other securities that entitle the holder to vote for the election of directors. ORIX may also exercise certain registration rights pursuant to the Registration Rights Agreement between us and ORIX.

As a result of these rights and ORIX's beneficial ownership of our common stock, ORIX could exert influence through its Board representation on our and our subsidiaries' business, operations and management, including our strategic plans, or, as a significant stockholder, on matters submitted to a vote of our stockholders, including mergers, consolidations and the sale of all or substantially all of our assets. This concentration of ownership of our common stock could delay or prevent proxy contests, mergers, tender offers, or other purchases of our common stock that might otherwise give our stockholders the opportunity to realize a premium over the then-prevailing market price for our shares. If ORIX exercises its registration rights to require us to register for sale the common stock held by ORIX or ORIX otherwise sells its common stock in the public markets, the price of our common stock may decline. This concentration of ownership may also adversely affect the liquidity of our common stock.

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;
- our ability to integrate acquisitions;
- announcements of significant contracts by us or our competitors;
- changes in our pricing policies or the pricing policies of our competitors;
- restatements of historical financial results and changes in financial forecasts;
- loss of one or more of our significant customers;
- legislation;
- changes in market valuation or earnings of our competitors;
- the trading volume of our common stock;
- the trading of our common stock on multiple trading markets, which takes place in different currencies and at different times; and
- general economic conditions.

In addition, the stock market in general, and the NYSE and the market for energy companies in particular, have experienced extreme price and volume fluctuations that have often been unrelated or disproportionate to the operating performance of particular companies affected. These broad market and industry factors may materially harm the market price of our common stock, regardless of our operating performance. In the past, following periods of volatility in the market price of a company's securities, securities class-action litigation has often been instituted against that company. Such litigation, if instituted against us, such as the recent class action filed on June 2018 by Mac Costas and discussed elsewhere in this report, 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.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

We currently lease corporate offices at 6140 Plumas street Reno, Nevada 89519 to which we moved in the second quarter of 2018. We also occupy an approximately 807,000 square foot office and manufacturing facility located in the Industrial Park of Yavne, Israel, which we lease from the Israel Land Administration. See Item 13 — "Certain Relationships and Related Transactions". In Turkey, we established and leased a facility to locally produce power plant components to our local customers. We also lease small offices in each of the countries in which we operate.

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

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

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

ITEM 3. LEGAL PROCEEDINGS

The information required with respect to this item can be found under "Commitments and Contingencies" in Note 22 of notes to the consolidated financial statements contained in this annual report and is incorporated by reference into this Item 8.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

PART II

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

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

As of February 25, 2020, there were 14 record holders of our common stock. On February 25, 2020, the closing price of our common stock as reported on the NYSE was $79.88 per share.

Dividends

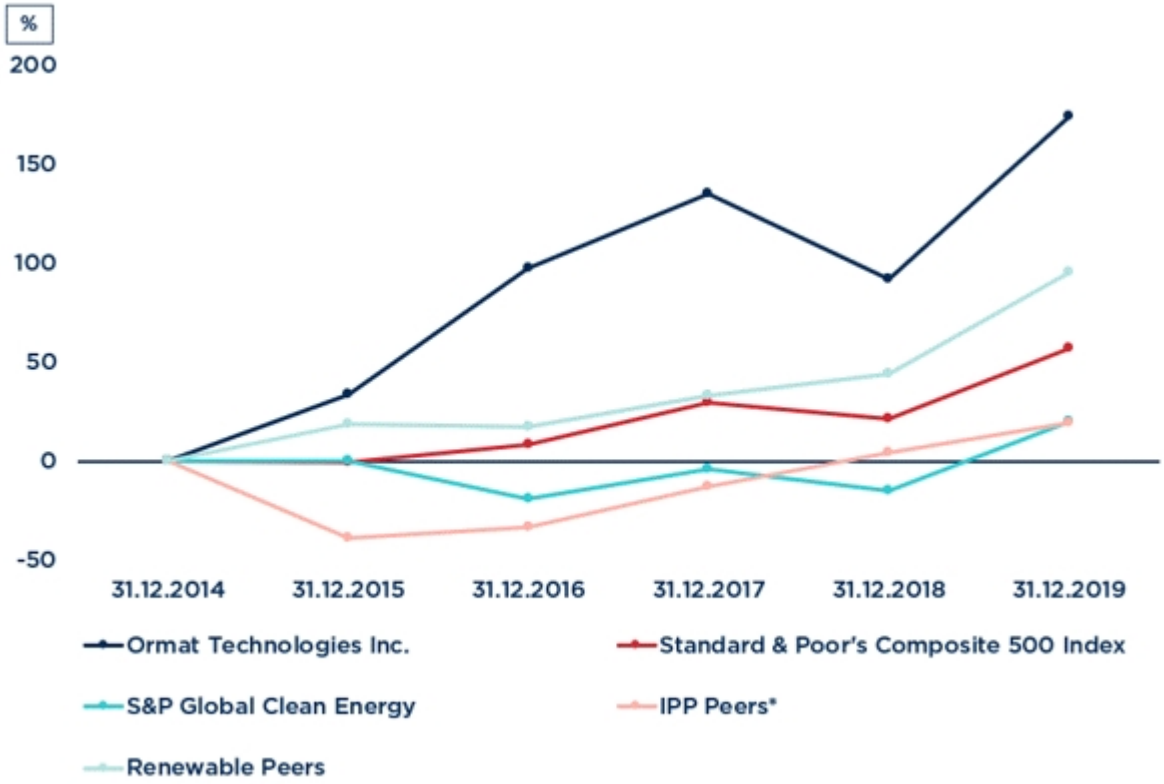
We have adopted a dividend policy pursuant to which we currently expect to distribute at least 20% of our annual profits available for distribution by way of quarterly dividends. In determining whether there are profits available for distribution, our Board will take into account our business plan and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

Date Declared	Dividend Amount per Share	Record Date	Payment Date
March 1, 2018	$ 0.23	March 14, 2018	March 29, 2018
May 7, 2018	$ 0.10	May 21, 2018	May 30, 2018
August 7, 2018	$ 0.10	August 21, 2018	August 29, 2018
November 6, 2018	$ 0.10	November 20, 2018	December 4, 2018
February 26, 2019	$ 0.11	March 14, 2019	March 28, 2019
May 6, 2019	$ 0.11	May 20, 2019	May 28, 2019
August 7, 2019	$ 0.11	August 20, 2019	August 27, 2019
November 6, 2019	$ 0.11	November 20, 2019	December 4, 2019
February 25, 2020	$ 0.11	March 12, 2020	March 26, 2020

Stock Performance Graph

The following performance graph represents the cumulative total shareholder return for the period December 30, 2014 through December 31, 2019 for our common stock, compared to the Standard and Poor's Composite 500 Index, and two peer groups.

Comparison of Cumulative Returns for the Period December 31, 2014 through December 31, 2019



	2015	2016	2017	2018	2019
Ormat Technologies Inc.	34.2 %	97.3 %	135.3 %	92.4 %	174.2 %
Standard & Poor's Composite 500 Index	-0.7 %	8.7 %	29.9 %	21.8 %	56.9 %
PBW - Invesco WilderHill Clean Energy ETF	0.2 %	-18.8 %	-4.1 %	-14.9 %	20.4 %
IPP Peers*	-38.8 %	-33.1 %	-13.0 %	4.3 %	19.8 %
Renewable Peers*	19.0 %	17.6 %	33.0 %	44.3 %	95.3 %

* IPP Peers are The AES Corporation, NRG Energy Inc. and Covanta Holding Corp.
** Renewable Energy (Renewable) Peers are Acciona S.A. and Nextera Energy, 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 we specifically request that such information be treated as soliciting material or specifically incorporate it by reference into a filing under the Securities Act or the Exchange Act.

Equity Compensation Plan Information

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

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

The following table sets forth our selected consolidated financial data for the years ended and at the dates indicated. We have derived the selected consolidated financial data for the years ended December 31, 2019, 2018 and 2017 and as of December 31, 2019 and 2018 from our audited consolidated financial statements set forth in Item 8 of this annual report. We have derived the selected consolidated financial data for the years ended December 31, 2016 and 2015 and as of December 31, 2017, 2016 and 2015 from our audited consolidated financial statements not included herein.

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

	Year Ended December 31,				
	2019	2018	2017	2016	2015
	(Dollars in thousands, except per share data)				
Statements of Operations Data:					
Revenues:					
Electricity	$ 540,333	$ 509,879	$ 465,593	$ 436,292	$ 375,920
Product	191,009	201,743	224,483	226,299	218,724
Energy Storage and Management Services	14,702	7,645	2,736	—	—
Total revenues	746,044	719,267	692,812	662,591	594,644
Cost of revenues:					
Electricity	312,835	298,255	266,840	261,573	242,612
Product	145,974	140,697	152,094	130,223	133,753
Energy Storage and Management Services	17,912	9,880	5,426	—	—
Total cost of revenues	476,721	448,832	424,360	391,796	376,365
Gross profit	269,323	270,435	268,452	270,795	218,279
Operating expenses:					
Research and development expenses	4,647	4,183	3,157	2,762	1,780
Selling and marketing expenses	15,047	19,802	15,600	16,424	16,077
General and administrative expenses	55,833	47,750	42,881	46,710	34,782
Impairment charge	—	13,464	—	—	—
Write-off of unsuccessful exploration activities	—	126	1,796	3,017	1,579
Operating Income	193,796	185,110	205,018	201,882	164,061
Other income (expense):					
Interest income	1,515	974	988	971	297
Interest expense, net	(80,384)	(70,924)	(54,142)	(67,389)	(72,577)
Derivatives and foreign currency transaction gains (losses)	624	(4,761)	2,654	(5,534)	(1,622)
Income attributable to sale of tax benefits	20,872	19,003	17,878	16,503	25,431
Other non-operating income (expense), net	880	7,779	(1,666)	(5,345)	(1,991)
Income from operations, before income tax and equity in earnings (losses) of investees	137,303	137,181	170,730	141,088	113,599
Income tax (provision) benefit	(45,613)	(34,733)	(21,664)	(37,059)	16,057
Equity in earnings (losses) of investees, net	1,853	7,663	(1,957)	(7,735)	(5,508)
Net Income	93,543	110,111	147,109	96,294	124,148
Net income attributable to noncontrolling interest	(5,448)	(12,145)	(14,695)	(7,586)	(3,776)
Net income attributable to the Company's stockholders	$ 88,095	$ 97,966	$ 132,414	$ 88,708	$ 120,372

	Year Ended December 31,				
	2019	2018	2017	2016	2015
	(Dollars in thousands, except per share data)				
Earnings per share attributable to the Company's stockholders:					
Basic:					
Net Income	$ 1.73	$ 1.93	$ 2.64	$ 1.79	$ 2.48
Diluted:					
Net Income	$ 1.72	$ 1.92	$ 2.61	$ 1.77	$ 2.45
Weighted average number of shares used in computation of earnings per share attributable to the Company's stockholders:					
Basic	50,867	50,643	50,110	49,469	48,562
Diluted	51,227	50,969	50,769	50,140	49,187
Dividend per share declared	$ 0.44	$ 0.53	$ 0.41	$ 0.52	$ 0.26
Balance Sheet Data (at end of year):					
Cash and cash equivalents	$ 71,173	$ 98,802	$ 47,818	$ 230,214	$ 185,919
Working capital	39,188	111,120	38,301	283,579	186,635
Property, plant and equipment, net (including construction-in process)	2,347,970	2,221,268	2,028,233	1,863,087	1,808,170
Total assets	3,250,494	3,121,350	2,623,864	2,461,569	2,273,982
Long-term debt (including current portion)	1,147,434	1,108,913	862,102	938,844	901,403
Equity	1,515,410	1,445,096	1,295,700	1,168,272	1,087,307

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 of Fiscal Year 2019 Revenues

For the year ended December 31, 2019, our total revenues increased by 3.7% (from $719.3 million to $746.0 million) over the previous year.

For the year ended December 31, 2019, Electricity segment revenues were $540.3 million, compared to $509.9 million for the year ended December 31, 2018, an increase of 6.0%. Product segment revenues for the year ended December 31, 2019 were $191.0 million, compared to $201.7 million for the year ended December 31, 2018, a decrease of 5.3%. Energy Storage and Management Services segment revenues for the year ended December 31, 2019 were $14.7 million, compared to $7.6 million for the year ended December 31, 2018.

During the years ended December 31, 2019 and 2018, our consolidated power plants generated 6,238,272 MWh and 5,857,963 MWh, respectively, an increase of 6.5%.

For the year ended December 31, 2019, our Electricity segment generated 72.4% of our total revenues (70.9% in 2018), while our Product segment generated 25.6% of our total revenues (28.0% in 2018), and our Energy Storage and Management Services segment generated 2.0% of our total revenues (1.1% in 2018).

For the year ended December 31, 2019, approximately 97.6% of our Electricity segment revenues were from PPAs with fixed energy rates which are not affected by fluctuations in energy commodity prices. We have variable price PPAs in California and Hawaii, which provide for payments based on the local utilities' avoided cost, which is the incremental cost that the power purchaser avoids by not having to generate such electrical energy itself or purchase it from others, as follows:

- The energy rates under the PPAs in California for each Heber 2 power plant in the Heber Complex and the G2 power plant in the Mammoth Complex, a total of between 30 to 40 MW, change primarily based on fluctuations in natural gas prices.

- The prices paid for electricity pursuant to the 25 MW PPA for the Puna Complex in Hawaii change primarily as a result of variations in the price of oil as well as other commodities. We recently signed a new PPA related to Puna with fixed prices (see "Recent Developments" below).

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

Electricity segment revenues are also subject to seasonal variations and are affected by higher-than-average ambient temperatures, as described below under "Seasonality".

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

Revenues attributable to our Energy Storage and Management Services segment are derived primarily from BSAAS systems, demand response and energy management services and may fluctuate between period to period. Pricing of such services and products are dependent on market supply and demand trends, market volatility, the need and price for ancillary services and other factors that may change over time.

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

Recent Developments

The most significant recent developments for our company and business during 2019 and 2020 to date are described below.

- In February 2020, we announced a transition of its senior management. Mr. Isaac Angel has decided to retire from his position as Chief Executive Officer, effective July 1, 2020, after six years of successful service to the Company, its employees and its shareholders. It is intended that Mr. Angel will become a member of Ormat's Board of Directors before his retirement as Chief Executive Officer and will continue to be employed by the Company through December 31, 2020 in order to assist with the management transition. Ormat's Board of Directors has appointed Mr. Blachar, the Company's President and Chief Financial Officer, to succeed Mr. Angel. Mr. Blachar will assume the role of Chief Executive Officer on July 1, 2020 upon Mr. Angel's retirement.

  Mr. Blachar will be succeeded in his role as Chief Financial Officer by Assaf Ginzburg, effective May 10, 2020, at which point Mr. Blachar will serve as President of the Company until assuming his role as Chief Executive Officer

on July 1, 2020. Mr. Ginzburg currently serves as Executive Vice President and Chief Financial Officer of Delek US Holdings, Inc. (NYSE: DK) and Delek Logistics Partners, LP (NYSE: DKL), and has over 15 years of experience in the energy industry. In his financial positions, Mr. Ginzburg supervised teams of senior financial professionals and has significant experience in all aspects of corporate finance, financial planning, tax, accounting and investor relations.

- As of February 2020, the reconstruction efforts at Puna continue. Building permits that are required for the construction and operation of the substation were delayed and were received in mid February 2020. HELCO continue with their efforts to complete the upgrade of the transmission network. On the field side, we completed the drilling of one production well that was blocked immediately after flow test of the well. We continue our field recovery work, which includes redrilling of existing wells, cleanouts and drilling of new wells and we expect initial power generation for testing during the second quarter of 2020. Commercial operation of the full generating capacity of the Puna power plant is expected in the third quarter assuming all permits are received, transmission network upgrade is complete and field recovery is successfully achieved.

- In January 2020, we signed two similar PPAs with Silicon Valley Clean Energy (SVCE) and Monterey Bay Community Power (MBCP). Under the PPAs, SVCE and MBCP will each purchase 7 MW (for a total of 14 MW) of power generated by the expected 30 MW Casa Diablo-IV (CD4) geothermal project located in Mammoth Lakes, California that is under construction. The PPAs are for a term of 10 years and have a fixed MWh price, which includes energy, capacity, environmental attributes, and all other ancillary benefits. The remaining 16 MW of generating capacity will be sold under an additional PPA with Southern California Public Power Authority, which was signed in early 2019. The CD4 power plant is expected to be on-line by the end of 2021, will be the first geothermal power plant built within the California Independent System Operator (CAISO) balancing authority in the last 30 years and will be the first in Ormat's portfolio that will sell its output to a Community Choice Aggregator.

- In December 2019, PGV and Hawaiian Electric's Hawaii Electric Light subsidiary reached an agreement on an amended and restated PPA for dispatchable geothermal power sold from Ormat's Puna complex, located on the Big Island of Hawaii. The new PPA extends the term until 2052 with an increased contract capacity of 46MW and a fixed price with no escalation, regardless of changes to fossil fuel pricing. The energy rate under the contract is fixed at $70 per MWh for all energy purchased during any contract year up to 227,000 MWh and $40 per MWh above 227,000 MWh. In addition, annual capacity payments under the contract are approximately $19.5 million. The amended PPA was filed with the Public Utilities Commission (PUC) on December 31, 2019 for its review and approval, which is anticipated during 2020. We are planning to replace ten 25-year-old steam units with two new Ormat binary units and to upgrade the existing auxiliary equipment. This upgraded facility will utilize the same amount of geothermal resource that the existing 38 MW facility requires. The COD of the new plant is expected during the first half of 2022. The existing PPA remains in effect, with current terms, until the expansion is completed, and the new plant reaches its COD.

- In December 2019, the tax extenders package was signed into law and retroactively revived and extended the full PTC for geothermal facilities. The PTC rules provide a tax credit for each kWh of electricity produced by the taxpayer from qualified renewable energy facilities. The PTC for geothermal facilities that expired at the end of 2017 was retroactively revived and extended through 2020, continuing U.S. support for the geothermal industry. This extension will drive and enhance our development of geothermal projects. This support contributes to the ongoing creation of new jobs in the geothermal industry as well as to the nation's energy independence.

- In November 2019, we announced that Mr. Doron Blachar, our CFO, was appointed to serve as our President, effective immediately. As President, Mr. Blachar assists our CEO, Isaac Angel, with the Company's strategic direction and operational management until he assumes Mr. Angel's position in July 1, 2020.

- In August 2019, we announced that one of our wholly owned subsidiaries that indirectly owns the 48MW McGinness Hills Phase 3 geothermal power plant entered into a partnership agreement with a private investor. Pursuant to the transaction agreement, the private investor acquired membership interests in the project for an initial purchase price of approximately $59.3 million and for which it will pay additional annual installments that are expected to amount to a total of approximately $9 million and can reach up to $22 million based on the actual generation. We will continue to consolidate, operate and maintain the power plant and will receive substantially all of the distributable cash flow generated by the power plant, and prior to December 2027 the private investor will receive substantially all of the tax attributes.

- In July 2019, we commenced commercial operation of our first-ever geothermal and solar hybrid project, a 7MW AC solar expansion of our Tungsten Mountain geothermal project in Churchill County, Nevada. The electricity

generated from the Tungsten solar power plant will be used to offset the equipment's energy use at the Tungsten geothermal facility, thus increasing the renewable energy delivered by the project under the Southern California Public Power Authority ("SCPPA") portfolio contract. SCPPA and the Los Angeles Department of Water and Power had the vision to enable this development through their innovative portfolio contract, which sought to maximize the output of their renewable facilities and furthering the transition away from coal power while maintaining a reliable power supply for Los Angeles.

- In July 2019 we announced that we signed and closed a set of agreements to acquire 49% of the Ijen geothermal project company, which is holding a PPA and geothermal license to develop the Ijen project in East Java, Indonesia, from a Medco Power subsidiary. Under the terms of the agreements, Ormat acquired 49% of the shares of the Ijen geothermal project company and committed to make additional funding for the project exploration and development, subject to specific conditions. A subsidiary of Medco Power retains 51% ownership of Our company. Ormat and Medco will develop the project jointly.

  The Ijen project assets, whose final capacity will be determined after exploration, include a geothermal concession and 30-year PPA for up to 110 MW capacity. The project is ready for exploration and development with some slim holes already drilled.

- In May 2019, we completed the drawdown of $23.5 million under a non-recourse loan agreement with Siemens Financial Services for the financing of Plumsted and Stryker, two 20 MW battery energy storage projects located in New Jersey. The loan bears interest of three months U.S. LIBOR plus 3.5% margin and its final maturity date is May 30, 2026.

- In March 2019, we entered into a first addendum ("First Addendum") to the Migdal Loan Agreement with several entities within the Migdal Group, a leading Israeli insurance company and institutional investor in Israel. The First Addendum provides us with an additional loan by the lenders in an aggregate principal amount of $50.0 million that will be repaid in 15 semi-annual payments of $2.1 million each, commencing on September 15, 2021, with a final payment of $18.5 million on March 15, 2029. The $50.0 million loan bears interest at a fixed rate of 4.6% per annum, payable semi-annually.

- In March 2019, we announced the signing of a PPA between one of our subsidiaries and SCPPA. Under the PPA, SCPPA will purchase 16MW of power generated by the expected 30MW Casa Diablo-IV ("CD4") geothermal project located in Mammoth Lakes, California. SCPPA will resell the output to the City of Colton. The CD4 power plant will be the first geothermal power plant built within the California Independent System Operator ("CAISO") balancing authority in the last 30 years. The 16MW of energy deliveries under the PPA will begin no later than the end of 2021 with an extension option. The PPA is for a term of 25 years and has a fixed price of $68 per MWh. We are in negotiations to sell the balance of 14MW to other offtakers or at the spot market.

- In January 2019, we entered into a $41.5 million subordinated loan agreement with Deutsche Investitions-und Entwicklungsgesellschaft mbH ("DEG") and on February 28, 2019, we completed a drawdown of the full loan amount, with a fixed interest rate of 6.04% for the duration of the loan. The loan is being repaid in 19 equal semi-annual principal installments, which commenced on June 21, 2019, with a final maturity date of June 21, 2028. Proceeds of the loan were used to refinance upgrades to Plant 1 of the Olkaria III Complex.

Opportunities, Trends and Uncertainties

Different trends, factors and uncertainties may impact our operations and financial condition, including many that we do not or cannot foresee. However, we believe that our results of operations and financial condition for the foreseeable future will be primarily affected by the following trends, factors and uncertainties that are from time to time also subject to market cycles:

- There has been increased demand for energy generated from geothermal and other renewable resources in the United States as costs for electricity generated from renewable resources have become more competitive. Much of this is attributable to legislative and regulatory requirements and incentives, such as state RPS and federal tax credits such as PTCs or ITCs (which are discussed in more detail in the section entitled "Government Grants and Tax Benefits" below). We believe that future demand for energy generated from geothermal and other renewable resources in the United States will be driven primarily by further commitment to, and implementation of, state RPS and greenhouse gas reduction initiatives.

- We accelerated our efforts to expand business development activities in developing countries where geothermal is considered a local resource that can provide a stable and cost effective solution to increase access to power. We expect that a variety of local governmental initiatives will create new opportunities for the development of new projects with the potential to realize higher returns on our equity as well as to create additional markets for our products. These initiatives include the award of long-term contracts to independent power generators, the creation of competitive wholesale markets for selling and trading energy, capacity and related energy products and the adoption of programs designed to encourage "clean" renewable and sustainable energy sources.

- In the Electricity segment, we expect intense domestic competition from the solar and wind power generation industries to continue and increase as well as increased competition from the solar combined with storage projects. While we believe the expected demand for renewable energy will be large enough to accommodate increased competition, any such increase in competition, including increasing amounts of renewable energy under contract as well as any further decline in natural gas prices attributable to increased production and reduction in energy storage costs are contributing to a reduction in electricity prices. However, despite increased competition from the solar and wind power generation industries, we believe that firm and flexible, base-load electricity, such as geothermal-based energy, will continue to be an important source of renewable energy in areas with commercially viable geothermal resources.

- In the Product segment, we see new opportunities in New Zealand, Turkey, the U.S., Asia Pacific and Central and South America. We have experienced increased competition from binary power plant equipment suppliers including the major steam turbine manufacturers. While we believe that we have a distinct competitive advantage based on our technology, accumulated experience and current worldwide share of installed binary generation capacity, an increase in competition may impact our ability to secure new purchase orders from potential customers. The increased competition may also leads to further reductions in the prices that we are able to charge for our binary equipment, as we recently experienced in Turkey, which in turn reduces our profitability. We are experiencing such competition in other locations where we operate which may have an adverse impact on the prices we can charge and our profitability.

- The average price per MWh, which is one of the metrics some investors may use to evaluate power plant revenues, can fluctuate from period to period. Based on total Electricity segment, we earned, on average, $86.6 and $87.0 per MWh in 2019 and 2018, respectively. Oil and natural gas prices, together with other factors that affect our Electricity segment revenues, could cause changes in our average price per MWh in the future.

- Turkey's geothermal market is one of the fastest growing markets in the geothermal industry worldwide, mainly due to governmental and regulatory support. Turkey is ranked fourth globally with an installed geothermal capacity of over 1,600 MW. Our revenue exposure to the Turkish market remained significant in 2019 and expects to reduce in 2020, due to slowdown in project development in the Turkish market. The continued deterioration in the Turkish economy, devaluation in the Turkish Lira and increase in local interest rates or a decline in government support for the development of geothermal power in the country could affect local demand for the geothermal equipment and services we provide, collection from our customers or the prices we may charge for such equipment and services. In addition, the impact of threatened or actual U.S. sanctions on the Turkish economy and the straining of U.S.-Turkey diplomatic relations may harm regional demand or price competitiveness for the geothermal equipment and services we provide in the Turkish market, in turn decreasing our Product segment profit margins, cash flows and financial condition. For the year ended December 31, 2019, we derived 12% and 47% of our Total revenues and Product revenues, respectively, from our Turkish operations. We are monitoring any change in the political and business environments that may affect our future business and operations in the country.

- Ormat established a manufacturing facility in Turkey in order to locally produce several power plant components that entitle our customer for increased incentives under the renewable energy laws. The use of local equipment in renewable energy based generating facilities in Turkey entitles such facilities to significant benefits under Turkish law, provided such facilities have obtained an RER Certificate from EMRA, which requires the issuance of a local certificate. If we do not obtain the local certificate, then some of our customers under the relevant supply agreements in Turkey may not be issued a RER Certificate based on the equipment we supply to them, and we will be required to make a payment to such customers equal to the amount of the expected lost benefit.

- In Kenya, we received three letters of assessment and preliminary findings from the KRA in relation to its review of the 2013 to 2017 tax years in which the KRA demanded we pay approximately $228.0 million including interest and penalties ($177.0 million principal). We are currently in different stages of discussions with the KRA on the matters included in their letters of assessment and preliminary findings and believe our tax positions for the issues

raised during the audit are sustainable based on the technical merits under Kenyan tax law. See further details under our Item 8 below.

- While the recently enacted Tax Act reduces the corporate tax rate, it is also expected to increase the cost of capital for renewable energy projects. Such projects often rely on "tax equity" as a core financing tool. Tax equity is a form of financing that is repaid partly or wholly in tax benefits and sometimes partly in cash. There are two types of federal income tax benefits on renewable energy projects: a tax credit and depreciation, or the ability to deduct the cost of the project. The reduction in the corporate tax rate from 35 percent to 21 percent reduces the value of the depreciation. Therefore, less tax equity can be raised on projects. The gap in the capital structure must be filled with debt and/or more expensive sponsor equity. The Tax Act allowed the full cost of equipment placed in service between September 28, 2017 and December 31, 2022 to be deducted immediately. However, the tax equity market is not expected to take advantage of this tax benefit and, because of the way tax equity works, we have had to take depreciation on a straight-line basis over 12 years rather than on a front-loaded basis over five years in some tax equity transactions, which leads to some further erosion in the present value of the depreciation. Other effects of the Tax Act are discussed later under Note 18 – Income Taxes to our consolidated financial statements.

Revenues

Sources of 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; the construction, installation and engineering of power plant equipment; the sale of energy storage services from our operating facilities and the sale of BSAAS systems and demand response and energy management services.

Revenues attributable to our Electricity segment are derived from the sale of electricity from our power plants pursuant to long-term PPAs. While approximately 97.6% of our Electricity revenues for the year ended December 31, 2019 were derived from PPAs with fixed price components, we have variable price PPAs in California and Hawaii. Accordingly, our revenues from those power plants may fluctuate.

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

Our PPAs generally provide for energy payments alone, or energy and capacity payments. Generally, capacity payments are payments calculated based on the amount of time and capacity 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 capacity target levels and the potential forfeiture of payments if we fail to meet certain minimum capacity target 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. Our more recent PPAs generally provide for energy payments alone with an obligation to compensate the off-taker for its incremental costs as a result of shortfalls in our supply.

Revenues attributable to our Product segment fluctuate between periods, primarily based on our ability to receive customer orders, the status and timing of such orders, delivery of raw materials and the completion of manufacturing. Larger customer orders for our products are typically the result of our sales efforts, our participation in, and winning tenders or requests for proposals issued by potential customers in connection with projects they are developing and orders by returning customers. Such projects often take a significant amount of time to design and develop and are subject to various contingencies, such as the customer’s ability to raise the necessary financing for a project. Consequently, we are generally unable to predict the timing of such orders for our products and may not be able to replace existing orders that we have completed with new ones. As a result, revenues from our Product segment fluctuate (sometimes extensively) from period to period.

Revenues attributable to our Energy Storage and Management Services segment are derived primarily from BSAAS systems, demand response and energy management services and may fluctuate period to period.

BSAAS are battery storage deals that are financed, owned and operated by us. BSAAS revenues are a combination of sales of the electricity back to the utilities and energy markets based on the prevailing market price for the electricity or for the energy or ancillary services. The energy and ancillary services revenue includes frequency regulation, standby capacity, synchronized reserve, reactive power and other related services. Additionally, when providing a "behind the customer meter solution" we also generate revenue from sharing savings generated from reducing the customer's utility bill. We also act as a general contractor on turnkey BESS for customers. BESS systems are owned by the customer and we provide the EPC for the project, delivering to the customer a fully operational system. Along with the BESS we also provide the management and operation of the battery for the customer for the life of the system which is typically 10 to 20 years. The EPC portion of the turnkey BESS revenue is a one-time charge and usually will be based on mile-stones or upon delivery.

Revenues attributable to our demand response and energy management services are derived by two methods. The first method is a fixed monthly or annual recurring fee for managing the customer's energy assets and monetizing them in either the energy markets or through reducing the customer's charges from their utility. The second method is through sharing the revenues or savings generated from monetizing their flexible electricity in the energy markets (revenue) or through reducing the customer's bill from the utility (savings). The second method is subject to energy price fluctuations and the available flexible electricity.

Revenues attributable to our Software as a Service are based on a fixed monthly or annual fee for energy management information and analytical services. Contract periods are typically 12 months or more. To date, we have experienced minimal customer churn.

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

	Revenues (dollars in thousands)			% of Revenues for Period Indicated		
	Year Ended December 31,			Year Ended December 31,		
	2019	2018	2017	2019	2018	2017
Revenues:						
Electricity	$ 540,333	$ 509,879	$ 465,593	72.4 %	70.9 %	67.2 %
Product	191,009	201,743	224,483	25.6	28.0	32.4
Energy Storage and Management Services	14,702	7,645	2,736	2.0	1.1	0.4
Total revenues	$ 746,044	$ 719,267	$ 692,812	100.0 %	100.0 %	100.0 %

Geographic Breakdown of Results of Operations

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

	Revenues in Thousands			% of Revenues for Period Indicated		
	Year Ended December 31,			Year Ended December 31,		
	2019	2018	2017	2019	2018	2017
Electricity Segment:						
United States	$ 333,797	$ 305,962	$ 295,484	61.8 %	60.0 %	63.5 %
International	206,536	203,917	170,109	38.2	40.0	36.5
Total	$ 540,333	$ 509,879	$ 465,593	100.0 %	100.0 %	100.0 %
Product Segment:						
United States	$ 30,562	$ 14,999	$ 2,912	16.0 %	7.4 %	1.3 %
International	160,447	186,744	221,571	84.0	92.6	98.7
Total	$ 191,009	$ 201,743	$ 224,483	100.0 %	100.0 %	100.0 %
Energy Storage and Management Services Segment:						
United States	$ 13,597	$ 7,645	$ 2,736	92.5 %	100.0 %	100.0 %
International	1,105	—	—	7.5	0.0	0.0
Total	$ 14,702	$ 7,645	$ 2,736	100.0 %	100.0 %	100.0 %

In 2019, 2018 and 2017, 49%, 54% and 57% of our revenues were derived from international operations, respectively, and our international operations were more profitable than our U.S. operations in each of those years. A substantial portion of international revenues came from Kenya and Turkey and, to a lesser extent, from Honduras, Guadeloupe, Guatemala and other countries. Our operations in Kenya contributed disproportionately to gross profit and net income. The contribution to combined pre-tax income of our domestic and foreign operations within our Electricity segment and Product segment differ in a number of ways.

Electricity Segment. Our Electricity segment domestic revenues were approximately 62%, 60% and 64% of our total Electricity segment for the years ended December 31, 2019, 2018 and 2017, respectively. However, domestic operations in our Electricity segment have higher costs of revenues and expenses than the foreign operations in our Electricity segment. Our foreign power plants are located in lower-cost regions, like Kenya, Guatemala, Honduras and Guadeloupe, which favorably impact payroll and maintenance expenses among other items. They are also newer than most of our domestic power plants and therefore tend to have lower maintenance costs and higher availability factors than our domestic power plants. Consequently, in 2019 the international operations of the segment accounted for 52% of our total gross profits, 59% of our net income and 48% of our EBITDA.

Product Segment. Our Product segment foreign revenues were 84%, 93% and 99% of our total Product segment revenues for the years ended December 31, 2019, 2018 and 2017, respectively. Our Product segment foreign activity also benefits from lower costs of revenues and expenses than Product segment domestic activity such as labor and transportation costs. Accordingly, our Product segment foreign activity contributes more than our Product segment domestic activity to our pre-tax income from operations.

Seasonality

Electricity generation from some of our geothermal power plants is subject to seasonal variations; in the winter, our power plants produce more energy primarily attributable to the lower ambient temperature, which has a favorable impact on the energy component of our Electricity segment revenues and the prices under many of our contracts are fixed throughout the year with no time-of-use impact. The prices paid for electricity under the PPAs for the Heber 2 power plant in the Heber Complex, the Mammoth Complex and the North Brawley power plant in California, the Raft River power plant in Idaho and the Neal Hot Springs power plant in Oregon, are higher in the months of June through September. The higher payments payable under these PPAs in the summer months partially offset the negative impact on our revenues from lower generation in the summer attributable to a higher ambient temperature. As a result, we expect the revenues in the winter months to be higher than the revenues in the summer months.

Breakdown of Cost of Revenues

Electricity Segment

The principal cost of revenues attributable to our operating power plants are operation and maintenance expenses comprised of salaries and related employee benefits, equipment expenses, costs of parts and chemicals, costs related to third-party services, lease expenses, royalties, startup and auxiliary electricity purchases, property taxes, insurance, depreciation and amortization and, for some of our projects, purchases of make-up water for use in our cooling towers. In our California power plants, our principal cost of revenues also includes transmission charges and scheduling charges. In some of our Nevada power plants we also incur transmission and wheeling charges. Some of these expenses, such as parts, third-party services and major maintenance, are not incurred on a regular basis. This results in fluctuations in our expenses and our results of operations for individual power plants from quarter to quarter. Payments made to government agencies and private entities on account of site leases where power plants are located are included in cost of revenues. Royalty payments, included in cost of revenues, are made as compensation for the right to use certain geothermal resources and are paid as a percentage of the revenues derived from the associated geothermal rights. Royalties constituted approximately 4.1% and 4.2% of Electricity segment revenues for the years ended December 31, 2019 and 2018, respectively.

Product Segment

The principal cost of revenues attributable to our Product segment are 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.

Energy Storage and Management Services Segment

The principal cost of revenues attributable to our Energy Storage and Management Services segment are direct costs attributable to providing services and equipment to our customers, direct costs associated with software development and the direct cost of operating batteries that are owned by Viridity. Direct costs include labor costs of our network operations center, the labor costs for engineering and implementation of services to customers, consulting services provided to customers and developing software and the labor associated with operations and maintenance for customer and our Viridity owned energy assets. Cost of revenues attributable to our Energy Storage and Management Services segment also include cost of equipment sold to customers in delivering our automated demand response and software services at a customer's location, the cost of batteries or other associated equipment that is sold to customers and for any third party related costs such as local construction, local engineering or other similar costs incurred in implementing and managing the customers' energy assets.

Critical Accounting Estimates and Assumptions

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

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

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

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

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

Our assessment of economic viability of an exploration project involves significant management judgment and uncertainties as to whether a commercially viable resource exists at the time we acquire land rights and begin to capitalize such costs. As a result, it is possible that our initial assessment of a geothermal resource may be incorrect and we will have to write off costs associated with the project that were previously capitalized. Due to the uncertainties inherent in geothermal exploration, historical impairments may not be indicative of future impairments. Included in construction-in-process are costs related to projects in exploration and development of $84.6 million and $71.0 million at December 31, 2019 and 2018, respectively. Included in these amounts at December 31, 2019 and 2018, respectively, are $17.0 million and $17.0 million, respectively, which relate to up-front bonus payments.

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

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

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

If our assets are considered to be impaired, the impairment to be recognized is the amount by which the carrying amount of the assets exceeds their fair value. Assets to be disposed of are reported at the lower of the carrying amount or fair value less costs to sell. We believe that for the year ended December 31, 2019, no impairment exists for any of our long-lived assets; however, estimates as to the recoverability of such assets may change based on revised circumstances. Estimates of the fair value of assets require estimating useful lives and selecting a discount rate that reflects the risk inherent in future cash flows.

- *Goodwill.* Goodwill represents the excess of the fair value of consideration transferred in the business combination transactions over the fair value of tangible and intangible assets acquired, net of the fair value of liabilities assumed and the fair value of any noncontrolling interest in the acquisitions. Goodwill is not amortized but rather subject to a periodic impairment testing on an annual basis (on December 31 of each year) or if an event occurs or circumstances change that would more likely than not reduce the fair value of reporting unit below its carrying amount. Additionally, we are permitted to first assess qualitative factors to determine whether a quantitative goodwill impairment test is necessary. Further testing is only required if the entity determines, based on the qualitative assessment, that it is more likely than not that a reporting unit's fair value is less than its carrying amount. Otherwise, no further impairment testing is required. An entity has the option to bypass the qualitative assessment for any reporting unit in any period and proceed directly to step one of the quantitative goodwill impairment test. This would not preclude the entity from performing the qualitative assessment in any subsequent period. The first step compares the fair value of the reporting unit to its carrying value, including goodwill. In January 2017, the FASB issued ASU 2017-04, Intangibles – Goodwill and Other (Topic 350), which was adopted by us in 2018, under which step two of the goodwill impairment test was eliminated. Step two measured a goodwill impairment test by comparing the implied fair value of reporting unit's goodwill with the carrying amount of that goodwill. Under ASU 2017-04, Intangibles – Goodwill and Other, an entity should recognize an impairment charge for the amount by which the carrying amount of the reporting unit exceeds its fair value as calculated under step one described above. However, the loss recognized should not exceed the total amount of goodwill allocated to that reporting unit

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

- *Accounting for Income Taxes.* Significant estimates are required to arrive at our consolidated income tax provision. 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, including the impacts of the passing of the Tax Act, considering the feasibility of ongoing tax planning strategies and the realization of tax credits and tax loss carryforwards. Valuation allowances related to deferred tax assets can be affected by changes in tax laws, statutory tax rates, and future taxable income. We have recorded a partial valuation allowance related to our U.S. deferred tax assets. In the future, if there is sufficient evidence that we will be able to generate sufficient future taxable income in the United States, we may be required to further reduce this valuation allowance, resulting in income tax benefits in our consolidated statement of operations.

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

New Accounting Pronouncements

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

Results of Operations

Our historical operating results in dollars and as a percentage of total revenues are presented below.

	Year Ended December 31,		
	2019	2018	2017
	(Dollars in thousands, except per share data)		
Revenues:			
Electricity	$ 540,333	$ 509,879	$ 465,593
Product	191,009	201,743	224,483
Energy storage and management services	14,702	7,645	2,736
Total revenues	746,044	719,267	692,812
Cost of revenues:			
Electricity	312,835	298,255	266,840
Product	145,974	140,697	152,094
Energy storage and management services	17,912	9,880	5,426
Total cost of revenues	476,721	448,832	424,360
Gross profit (loss)			
Electricity	227,498	211,624	198,753
Product	45,035	61,046	72,389
Energy storage and management services	(3,210)	(2,235)	(2,690)
Total gross profit	269,323	270,435	268,452
Operating expenses:			
Research and development expenses	4,647	4,183	3,157
Selling and marketing expenses	15,047	19,802	15,600
General and administrative expenses	55,833	47,750	42,881
Impairment charge	—	13,464	—
Write-off of unsuccessful exploration activities	—	126	1,796
Operating income	193,796	185,110	205,018
Other income (expense):			
Interest income	1,515	974	988
Interest expense, net	(80,384)	(70,924)	(54,142)
Derivatives and foreign currency transaction gains (losses)	624	(4,761)	2,654
Income attributable to sale of tax benefits	20,872	19,003	17,878
Other non-operating income (expense), net	880	7,779	(1,666)
Income from operations before income tax and equity in earnings (losses) of investees	137,303	137,181	170,730
Income tax (provision) benefit	(45,613)	(34,733)	(21,664)
Equity in earnings (losses) of investees, net	1,853	7,663	(1,957)
Net Income	93,543	110,111	147,109
Net income attributable to noncontrolling interest	(5,448)	(12,145)	(14,695)
Net income attributable to the Company's stockholders	$ 88,095	$ 97,966	$ 132,414
Earnings per share attributable to the Company's stockholders:			
Basic:			
Net income	$ 1.73	$ 1.93	$ 2.64
Diluted:			
Net income	$ 1.72	$ 1.92	$ 2.61
Weighted average number of shares used in computation of earnings per share attributable to the Company's stockholders:			
Basic	50,867	50,643	50,110
Diluted	51,227	50,969	50,769

Results as a percentage of revenues

	Year Ended December 31,		
	2019	**2018**	**2017**
Revenues:			
Electricity	72.4 %	70.9 %	67.2 %
Product	25.6	28.0	32.4
Energy storage and management services	2.0	1.1	0.4
Total revenues	100.0	100.0	100.0
Cost of revenues:			
Electricity	57.9	58.5	57.3
Product	76.4	69.7	67.8
Energy storage and management services	121.8	129.2	198.3
Total cost of revenues	63.9	62.4	61.3
Gross profit (loss)			
Electricity	42.1	41.5	42.7
Product	23.6	30.3	32.2
Energy storage and management services	(21.8)	(29.2)	(98.3)
Total gross profit	36.1	37.6	38.7
Operating expenses:			
Research and development expenses	0.6	0.6	0.5
Selling and marketing expenses	2.0	2.8	2.3
General and administrative expenses	7.5	6.6	6.2
Impairment charge	0.0	1.9	0.0
Write-off of unsuccessful exploration activities	0.0	0.0	0.3
Operating income	26.0	25.7	29.6
Other income (expense):			
Interest income	0.2	0.1	0.1
Interest expense, net	(10.8)	(9.9)	(7.8)
Derivatives and foreign currency transaction gains (losses)	0.1	(0.7)	0.4
Income attributable to sale of tax benefits	2.8	2.6	2.6
Other non-operating income (expense), net	0.1	1.1	(0.2)
Income from continuing operations before income tax and equity in earnings (losses) of investees	18.4	19.1	24.6
Income tax (provision) benefit	(6.1)	(4.8)	(3.1)
Equity in earnings (losses) of investees, net	0.2	1.1	(0.3)
Net Income	12.5	15.3	21.2
Net income attributable to noncontrolling interest	(0.7)	(1.7)	(2.1)
Net income attributable to the Company's stockholders	11.8 %	13.6 %	19.1 %

Comparison of the Year Ended December 31, 2019 and the Year Ended December 31, 2018

Total Revenues (Dollars in millions)

	Year Ended December 31, 2019	Year Ended December 31, 2018	Change
	(Dollars in millions)		
Electricity segment revenues	$ 540.3	$ 509.9	6 %
Product segment revenues	191.0	201.7	(5)%
Energy Storage and Management Services segment revenues	14.7	7.6	92 %
Total Revenues	**$ 746.0**	**$ 719.3**	**4 %**

Electricity Segment

Revenues attributable to our Electricity segment for the year ended December 31, 2019 were $540.3 million, compared to $509.9 million for the year ended December 31, 2018, representing a 6.0% increase from the prior period. This increase was primarily attributable to: (i) the commencement of commercial operation of the third phase of our McGinness Hills Complex in Nevada, effective December 2018, which generated total complex revenues of $96.9 million for the year ended December 31, 2019 compared to $65.1 million for the year ended December 31, 2018; (ii) the consolidation of USG which was acquired on April 24, 2018, and contributed $35.6 million for the year ended December 31, 2019, compared to $21.4 million for the year ended December 31, 2018; and (iii) the commencement of commercial operation of our Plant 1 expansion project in the Olkaria III Complex in Kenya, effective June 2018. The increase was partially offset by (i) the shutdown of our Puna power plant following the Kilauea volcanic eruption on May 3, 2018 which resulted in a reduction of $15.5 million in revenues compared to the year ended December 31, 2018; and (ii) a decrease in generation at some of our other power plants that were taken offline to address maintenance issues in the ordinary course of business as well as curtailments by the offtaker in the Olkaria complex.

Power generation in our power plants increased by 6.5% from 5,857,963 MWh in the year ended December 31, 2018 to 6,238,272 MWh in the year ended December 31, 2019, primarily because of an increase in generation due to the commencement of commercial operation of the third phase of our McGinness Hills Complex in Nevada, Plant 1 expansion in Kenya and the acquisition of USG. The increase was partially offset by (i) the shutdown of our Puna power plant following the Kilauea Volcanic Eruption and (ii) lower generation at some of our other power plants mainly due to higher ambient temperature and maintenance issues in the ordinary course of business as well as curtailments by the offtaker in the Olkaria III complex.

Product Segment

Revenues attributable to our Product segment for the year ended December 31, 2019 were $191.0 million, compared to $201.7 million for the year ended December 31, 2018, representing a 5.3% decrease from the prior period. The decrease in our Product segment revenues was mainly due to projects that were completed in Turkey in 2018, which accounted for $91.1 in Product segment revenues in the year ended December 31, 2018, which were partially offset by (i) the start of four new projects in Turkey, New Zealand and Chile in 2019, which provided $90.3 million in revenue for the year ended December 31, 2019; and (ii) other projects mainly in Turkey and the U.S., which were started in 2018, and provided $72.2 million in revenue for the year ended December 31, 2019 compared to $90.0 million for the year ended December 31, 2018.

Energy Storage and Management Services Segment

Revenues attributable to our Energy Storage and Management Services segment for the year ended December 31, 2019 were $14.7 million compared to $7.6 million for the year ended December 31, 2018. The increase was mainly driven by the start of operation of two energy storage facilities in the PJM market. The Energy Storage and Management Services segment includes revenues from the delivery of energy storage demand response and energy management services.

Total Cost of Revenues (Dollars in millions)

	Year Ended December 31, 2019	Year Ended December 31, 2018	Change
	(Dollars in millions)		
Electricity segment cost of revenues	$ 312.8	$ 298.3	4.9 %
Product segment cost of revenues	146.0	140.7	3.8 %
Energy Storage and Management Services segment cost of revenues	17.9	9.9	81.3 %
Total Cost of Revenues	**$ 476.7**	**$ 448.8**	**6.2 %**

Electricity Segment

Total cost of revenues attributable to our Electricity segment for the year ended December 31, 2019 was $312.8 million, compared to $298.3 million for the year ended December 31, 2018, representing a 4.9% increase from the prior period. This increase was primarily attributable to: (i) additional cost of revenues from the commencement of commercial operation of the third phase of our McGinness Hills Complex plant in Nevada, effective December 2018 and (ii) commencement of commercial operation of our Plant 1 expansion project in the Olkaria III Complex in Kenya, effective June 2018. As a percentage of total Electricity revenues, the total cost of revenues attributable to our Electricity segment for the year ended December 31, 2019 was 57.9%, compared to 58.5% for the year ended December 31, 2018. This decrease was primarily attributable to an increase in gross profit due to the commencement of commercial operation of the third phase of our McGinness Hills Complex and from our assets that were acquired from USG and contributed partially in 2018, partly offset by the Puna power plant in Hawaii, for which we recorded cost of revenues with no associated revenues due to the shut-down of the power plant following the Kilauea volcanic eruption in May 3, 2018. The cost of revenues attributable to our international power plants was 23.6% of our Electricity segment cost of revenues.

Product Segment

Total cost of revenues attributable to our Product segment for the year ended December 31, 2019 was $146.0 million, compared to $140.7 million for the year ended December 31, 2018, representing a 3.8% increase from the prior period. This increase was primarily attributable to higher competition, different product scope and different margins in the various sales contracts we entered into for the Product segment during these periods, specifically related to two large but lower margin contracts in Turkey that had an impact on revenue and related cost of revenues in the year ended December 31, 2019. As a percentage of total Product segment revenues, our total cost of revenues attributable to our Product segment for the year ended December 31, 2019 was 76.4%, compared to 69.7% for the year ended December 31, 2018.

Energy Storage and Management Services Segment

Cost of revenues attributable to our Energy Storage and Management Services segment for the year ended December 31, 2019 were $17.9 million as compared to $9.9 million in the year ended December 31, 2018. The increase was mainly driven by the start of operation of two storage energy facilities in the PJM market. The Energy Storage and Management Services segment includes cost of revenues related to the delivery of energy storage, demand response and energy management services.

Research and Development Expenses

Research and development expenses for the year ended December 31, 2019 were $4.6 million, compared to $4.2 million for the year ended December 31, 2018.

Selling and Marketing Expenses

Selling and marketing expenses for the year ended December 31, 2019 were $15.0 million, compared to $19.8 million for the year ended December 31, 2018. This decrease was primarily due to the $5.0 million termination fee paid to NV Energy related to the termination of the Galena 2 PPA in the year ended December 31, 2018. Selling and marketing expenses constituted 2.0% of total revenues for the year ended December 31, 2019, compared to 2.1%, excluding the termination fee, for the year ended December 31, 2018.

General and Administrative Expenses

General and administrative expenses for the year ended December 31, 2019 were $55.8 million, compared to $47.8 million for the year ended December 31, 2018. The increase was primarily attributable to a $10.3 million income adjustment in the year ended December 31, 2018, in respect of an earn out related to the acquisition of our Viridity business, partially offset by (i) higher expenses in the year ended December 31, 2018 related to our identification of a material weakness related to taxes in the fourth quarter of 2017 and the restatement of 2017 financial statements; (ii) costs related to the acquisition of USG in 2018; and (iii) a decrease in professional fees. General and administrative expenses for the year ended December 31, 2019 constituted 7.5% of total revenues for such period, compared to 8.1%, excluding the earn out adjustment, for the year ended December 31, 2018.

Goodwill Impairment Charge

There was no goodwill impairment charge for the year ended December 31, 2019. Goodwill impairment charge for the year ended December 31, 2018 was $13.5 million related to the acquisition of our Viridity business.

Operating Income

Operating income for the year ended December 31, 2019 was $193.8 million, compared to $185.1 million for the year ended December 31, 2018, representing a 4.7% increase from the prior period. Operating income attributable to our Electricity segment for the year ended December 31, 2019 was $177.2 million compared to $155.5 million for the year ended December 31, 2018. Operating income attributable to our Product segment for the year ended December 31, 2019 was $23.2 million, compared to $38.1 million for the year ended December 31, 2018. Operating loss attributable to our Energy Storage and Management Services segment for the year ended December 31, 2019 was $6.6 million compared to $8.5 million for the year ended December 31, 2018.

Interest Expense, Net

Interest expense, net, for the year ended December 31, 2019 was $80.4 million, compared to $70.9 million for the year ended December 31, 2018, representing a 13.3% increase from the prior period. This increase was primarily due to (i) $100.0 million and $50.0 million of proceeds from a senior unsecured loan received on March 22, 2018 and March 25, 2019, respectively; (ii) $96.0 million debt as part of the acquisition of USG; (iii) $114.7 million of proceeds from a limited recourse loan received on October 29, 2018 from OPIC for financing the Honduras power plant; and (iv) $41.5 million of proceeds from a full recourse loan received on January 4, 2019 from DEG for financing the Kenya power plant, partially offset due to lower interest expense as a result of principal payments of long term debt.

Derivatives and Foreign Currency Transaction Gains (Losses)

Derivatives and foreign currency transaction gains for the year ended December 31, 2019 were $0.6 million, compared to losses of $4.8 million for the year ended December 31, 2018. Derivatives and foreign currency transaction gains for the year ended December 31, 2019 were attributable primarily to gains from foreign currency forward contracts, which were not accounted for as hedge transactions. Derivatives and foreign currency transaction losses for the year ended December 31, 2018 were primarily attributable to losses from foreign currency forward contracts, which were not accounted for as hedge transactions.

Income Attributable to Sale of Tax Benefits

Income attributable to the sale of tax benefits for the year ended December 31, 2019 was $20.9 million, compared to $19.0 million for the year ended December 31, 2018. Tax equity is a form of financing used for renewable energy projects. This income primarily represents the value of PTCs and taxable income or loss generated by certain of our power plants allocated to investors under tax equity transactions.

Other Non-Operating Income (Expense), Net

Other non-operating income, net for the year ended December 31, 2019 was $0.9 million, compared to other non-operating expense, net of $7.8 million for the year ended December 31, 2018. Other non-operating income for the year ended December 31, 2019 mainly includes an income of $1.0 million from the sale of PG&E receivables relating to the January 2019 monthly invoice which was not paid as it occurred before PG&E filed for reorganization under Chapter 11 bankruptcy. Other non-operating income for the year ended December 31, 2018 mainly includes income of a $7.2 million insurance settlement of our Puna power plant rig which was damaged by the Kilauea volcanic eruption.

Income from operations, before income taxes and equity in earnings of investees

Income from operations, before income taxes and equity in earnings of investees for the year ended December 31, 2019 was $137.3 million, compared to $137.2 million for the year ended December 31, 2018, representing an 0.1% increase from the prior period. The income is primarily attributable to our foreign operations.

Income Taxes

Income tax provision for the year ended December 31, 2019, was $45.6 million, an increase of $10.9 million compared to an income tax provision of $34.7 million for the year ended December 31, 2018. Our effective tax rate for the year ended December 31, 2019 and 2018, was 33.2% and 25.3%, respectively. Our effective tax rate is primarily based upon the composition of our income in different countries and changes related to valuation allowances in the United States. Our aggregate effective tax rate for the year ended December 31, 2019 differs from the 21% U.S. federal statutory tax rate primarily due to the impact of global intangible low tax income (GILTI) and the mix of business in various countries with higher and lower statutory rates than the federal rate, partially offset by the generation of additional foreign tax credits through amended tax returns of prior periods.

On December 22, 2017, the U.S. government signed into law the Tax Act. The Tax Act makes significant changes to the U.S. tax code, including, but not limited to, (1) reducing the U.S. federal corporate income tax rate from 35 percent to 21 percent; (2) the transition of U.S. international taxation from a worldwide tax system to a territorial system (GILTI, BEAT, Dividends Received Deduction); (3) one-time transition tax on undistributed earnings of foreign subsidiaries as of December 31, 2017; (4) eliminating the corporate alternative minimum tax (5) creating a new limitation on deductible interest expense; and (6) changing rules related to uses and limitations of net operating loss carryforwards created in tax years beginning after December 31, 2017.

Equity in Earnings (losses) of investees, net

Equity in earnings (losses) of investees, net in the year ended December 31, 2019 was $1.9 million, compared to $7.7 million in the year ended December 31, 2018. Equity in earnings of investees, net is primarily derived from our 12.75% share in the earnings or losses in the Sarulla complex. The decrease was mainly attributable to a decrease in gross margin due to well-field issues in the NIL power plant which resulted in lower generation.

Net Income

Net income for the year ended December 31, 2019 was $93.5 million, compared to $110.1 million for the year ended December 31, 2018, representing a decrease of $16.6 million from the prior period. This decrease in net income was primarily attributable to an increase in income tax provision of $10.9 million, an increase of $9.5 million in interest expense, net, a decrease of $6.9 million in other non-operating income, and a decrease of $5.8 million in equity in earnings of investees, net, partially offset by an increase of $8.7 million in operating income and an increase of $5.4 million in derivatives and foreign currency transaction gains, as discussed above.

Net Income attributable to the Company's Stockholders

Net income attributable to the Company's stockholders for the year ended December 31, 2019 was $88.1 million, compared to $98.0 million for the year ended December 31, 2018, which represents a decrease of $9.9 million. This decrease was attributable to the decrease in net income of $16.6 million, offset partially by a decrease of $6.7 million in net income attributable to noncontrolling interest mainly due to the shutdown of the Puna power plant in Hawaii, all as discussed above.

Comparison of the year ended December 31, 2018 and the year ended December 31, 2017

Total Revenues

Total revenues for the year ended December 31, 2018 were $719.3 million, compared to $692.8 million for the year ended December 31, 2017, representing a 3.8% increase from the prior period. This increase was attributable to our Electricity segment, in which revenues increased by $44.3 million or 9.5% compared to the corresponding period in 2017 and our Energy Storage and Management Services segment in which revenues increased by $4.9 million or 179.4%, as a result of revenues generated by our Viridity business from the delivery of energy storage, demand response and energy management services. This increase was partially offset by a decrease of $22.7 million, or 10.1% in our Product segment revenues compared to the corresponding period in 2017.

Electricity Segment

Revenues attributable to our Electricity segment for the year ended December 31, 2018, were $509.9 million, compared to $465.6 million for the year ended December 31, 2017, representing a 9.5% increase from the prior period. This increase was primarily attributable to: (i) the commencement of commercial operation of our Platanares power plant in Honduras, effective September 2017, with revenues of $34.4 million for the year ended December 31, 2018 compared to $10.0 million for the year ended December 31, 2017; (ii) the consolidation of USG which was acquired on April 24, 2018, with revenues of $21.4 million for the year ended December 31, 2018; (iii) the commencement of commercial operation of our Tungsten Mountain power plant in Nevada, effective December 2017, with revenues of $15.7 million for the year ended December 31, 2018 compared to $2.2 million for the year ended December 31, 2017; (iv) the commencement of commercial operation of our Plant 1 expansion project in the Olkaria III Complex in Kenya, effective June 2018; and (v) higher energy rates under the new Ormesa 1 PPA commencing in December 2017. The increase was partially offset due to (i) a decrease in revenues at our Puna power plant that was shut down immediately following the Kilauea volcanic eruption on May 3, 2018 and (ii) a decrease in generation at some of our other power plants that were taken offline to address maintenance issues and enhancements, high ambient temperature and curtailments.

Power generation in our power plants increased by 6.7% from 5,489,234 MWh in the year ended December 31, 2017 to 5,857,963 MWh in the year ended December 31, 2018, primarily because of an increase in generation due to the commencement of commercial operations of our Platanares power plant in Honduras, Tungsten Mountain power plant in Nevada, and Plant 1 expansion in Kenya and due to the acquisition of USG. The increase was partially offset by a decrease in generation at (i) our Puna power plant due to the Kilauea Volcanic Eruption and (ii) some of our other power plants mainly due to maintenance issues and high ambient temperature.

Product Segment

Revenues attributable to our Product segment for the year ended December 31, 2018 were $201.7 million, compared to $224.5 million for the year ended December 31, 2017, representing a 10.1% decrease from the prior period. We recognized approximately $31.4 million and $23.1 million in revenues, from the New Zealand and China projects, respectively, in the year ended December 31, 2017, compared to $8.8 million and $0.5 million in the year ended December 31, 2018. The projects were completed in 2018. The decrease in our Product segment revenues was also attributable to other projects in Turkey, which were completed in 2017, and by a decrease in revenues as a result of completion of our contracts for geothermal projects in Chile and the Sarulla project. The decrease was partially offset by the start of new projects in Turkey, which provided $154.3 million in revenue recognized during the year ended December 31, 2018.

Energy Storage and Management Services *Segment*

Revenues attributable to our Energy Storage and Management Services segment for the year ended December 31, 2018 were $7.6 million compared to $2.7 million for the year ended December 31, 2017. The Energy Storage and Management Services segment includes revenues from the delivery of energy storage demand response and energy management services by our Viridity business following the acquisition of substantially all of the business and assets of Viridity Energy, Inc. on March 15, 2017.

Total Cost of Revenues

Total cost of revenues for the year ended December 31, 2018 was $448.8 million, compared to $424.4 million for the year ended December 31, 2017, representing a 5.8% increase from the prior period. This increase was attributable to an increase of $31.4 million, or 11.8%, in cost of revenues from our Electricity segment and an increase of $4.5 million, or 82.1% from our Energy Storage and Management Services segment generated by our Viridity business. This increase was partially offset by a 7.5% decrease in our Product segment cost of revenues compared to the corresponding period in 2017. As a percentage of total revenues, our total cost of revenues for the year ended December 31, 2018 increased to 62.4%, compared to 61.3% for the year ended December 31, 2017.

Electricity Segment

Total cost of revenues attributable to our Electricity segment for the year ended December 31, 2018 was $298.3 million, compared to $266.8 million for the year ended December 31, 2017, representing a 11.8% increase from the prior period. This increase was primarily attributable to additional cost of revenues from the commencement of commercial operation of our Platanares power plant in Honduras, effective September 2017, our Tungsten Mountain power plant in Nevada, effective December 2017 and commencement of commercial operation of our Plant 1 expansion project in the Olkaria III Complex in Kenya, effective June 2018, (ii) approximately $8.0 million higher costs compared to the same period 2017 related to pump failures that we had to replace in some of our power plants and (iii) the consolidation of USG which we acquired on April 24, 2018. As a percentage of total Electricity segment revenues, the total cost of revenues attributable to our Electricity segment for the year ended December 31, 2018 was 58.5%, compared to 57.3% for the year ended December 31, 2017. The cost of revenues attributable to our international power plants was 24.7% of our Electricity segment cost of revenues.

Product Segment

Total cost of revenues attributable to our Product segment for the year ended December 31, 2018 was $140.7 million, compared to $152.1 million for the year ended December 31, 2017, representing a 7.5% decrease from the prior period. This decrease was primarily attributable to decrease in Product segment revenues, as discussed above. As a percentage of total Product segment revenues, our total cost of revenues attributable to the Product segment for the year ended December 31, 2018 was 69.7%, compared to 67.8% for the year ended December 31, 2017. This increase was primarily attributable to the higher competition, different product scope and different margins in the various sales contracts we entered into for the Product segment during these periods.

Energy Storage and Management Services *Segment*

Cost of revenues attributable to our Energy Storage and Management Services segment for the year ended December 31, 2018 were $9.9 million, compared to $5.4 million for the year ended December 31, 2017. The Energy Storage and Management Services segment includes cost of revenues related to the delivery of energy storage, demand response and energy management services by our Viridity business.

Research and Development Expenses

Research and development expenses for the year ended December 31, 2018 were $4.2 million, compared to $3.2 million for the year ended December 31, 2017.

Selling and Marketing Expenses

Selling and marketing expenses for the year ended December 31, 2018 were $19.8 million, compared to $15.6 million for the year ended December 31, 2017. This increase was primarily due to the $5.0 million termination fee paid to NV Energy related to the termination of the Galena 2 PPA. The increase was partially offset as a result of lower sales commissions related to our Product segment due to lower revenues and lower commissions due to the nature of the contracts. Selling and marketing expenses for the year ended December 31, 2018, excluding the termination fee, constituted 2.1% of total revenues for such year, compared to 2.3% for the year ended December 31, 2017.

General and Administrative Expenses

General and administrative expenses for the year ended December 31, 2018 were $47.8 million, compared to $42.9 million for the year ended December 31, 2017. This increase was primarily attributable to (i) general and administrative expenses resulting from first time inclusion of USG, (ii) general and administrative expenses from our Viridity business which we acquired on March 15, 2017; and (iii) an increase in costs associated with our identification of a material weakness related to taxes in the fourth quarter of 2017 and the additional work and controls to compensate for such material weakness as well as the restatement of second, third and fourth quarter financial statements and its full-year 2017 financial statements and related expenses. The increase was partially offset due to a $10.3 million adjustment in respect of an earn out related to the acquisition of our Viridity business. General and administrative expenses for the year ended December 31, 2017 included $2.1 million charge for stock-based compensation expense associated with the acceleration of the vesting period of the stock options previously held by our CEO and CFO and exercised in connection with ORIX's acquisition of 22% of our Company.

Goodwill Impairment Charge

Goodwill impairment charge for the year ended December 31, 2018 was $13.5 million related to the acquisition of our Viridity business. There was no goodwill impairment charge for the year ended December 31, 2017.

Write-off of Unsuccessful Exploration Activities

Write-off of unsuccessful exploration activities for the year ended December 31, 2018 was $0.1 million, compared to $1.8 million for the year ended December 31, 2017. The write-off of unsuccessful exploration activities for the year ended December 31, 2017, included costs related to the Glass Buttes site in Oregon, which we determined in the fourth quarter of 2017, would not support commercial operations.

Operating Income

Operating income for the year ended December 31, 2018 was $185.1 million, compared to $205.0 million for the year ended December 31, 2017, representing a 9.7% decrease from the prior period. The decrease in operating income was primarily attributable to the $13.5 million goodwill impairment charge, the decrease in our Product segment gross margin, the $5.0 million termination fee of the Galena 2 PPA, and the increase in general and administrative expenses, as discussed above. The decrease was partially offset by an increase in our gross margin in our Electricity segment, also discussed above. Operating income attributable to our Electricity segment for the year ended December 31, 2018 was $155.5 million, compared to $157.6 million for the year ended December 31, 2017. Operating income attributable to our Product segment for the year ended December 31, 2018 was $38.1 million, compared to $50.5 million for the year ended December 31, 2017. Operating loss attributable to our Energy Storage and Management Services segment for the year ended December 31, 2018 was $8.5 million compared to a loss of $3.1 million for the year ended December 31, 2017.

Interest Expense, Net

Interest expense, net, for the year ended December 31, 2018 was $70.9 million, compared to $54.1 million for the year ended December 31, 2017, representing a 31.0% increase from the prior period. This increase was primarily due to: (i) $100.0 million of proceeds from a senior unsecured loan received on March 22, 2018; (ii) net increase in our revolving credit lines with commercial banks; and (iii) a $3.5 million increase related to a decrease in interest capitalized to projects; (iv) additional debt as part of the acquisition of USG, and (v) $4.3 million increase in interest related to the sale of tax benefits; and (vi) $114.7 million of proceeds from a limited recourse loan received on October 29, 2018 from OPIC for financing the Honduras power plant, offset partially due to lower interest expense as a result of principal payments of long term debt.

Derivatives and Foreign Currency Transaction Losses

Derivatives and foreign currency transaction losses for the year ended December 31, 2018 were $4.8 million, compared to gains of $2.7 million for the year ended December 31, 2017. Derivatives and foreign currency transaction losses for the year ended December 31, 2018 were attributable primarily to losses from foreign currency forward contracts, which were not accounted for as hedge transactions. Derivatives and foreign currency transaction gains for the year ended December 31, 2017 were primarily attributable to gains from foreign currency forward contracts, which were not accounted for as hedge transactions.

Income Attributable to Sale of Tax Benefits

Tax equity is a form of financing used for renewable energy projects. In such financings, the Company we may realize income when the financing is put in place or over time as a consequence of how the financing is structured. Income attributable to the sale of tax benefits to institutional equity investors (as described in our financial statements below under "OPC Transaction", "ORTP Transaction" and "Opal Geo Transaction") for the year ended December 31, 2018 was $19.0 million, compared to $17.9 million for the year ended December 31, 2017. This income primarily represents the value of PTCs and taxable income or loss generated by Opal Geo and Tungsten allocated to the investor in the year ended December 31, 2018 compared to the value of PTCs and taxable income or loss generated by Opal Geo allocated to the investors in the year ended December 31, 2017.

Other Non-Operating Income (loss)

Other non-operating income, net for the year ended December 31, 2018 was $7.8 million, compared to Other non-operating expense, net of $1.7 million for the year ended December 31, 2017. Other non-operating expense, net for the year ended December 31, 2018 includes an income of $7.2 million insurance settlement of our Puna power plant rig which was damaged by the Kilauea volcanic eruption. Other non-operating expense, net for the year ended December 31, 2017 includes a make whole premium of $1.9 million resulting from the prepayment of $14.3 million aggregate principal amount of our OFC Senior Secured Notes and $11.8 million aggregate principal amount of our DEG Loan.

Income from operations, before income taxes and equity in losses of investees

Income from operations, before income taxes and equity in losses of investees for the year ended December 31, 2018 was $137.2 million, compared to $170.7 million for the year ended December 31, 2017, representing a 19.7% decrease from the prior period. The income is primarily attributable to our foreign operations. This decrease was driven by the decrease in our domestic operations resulting mainly from the goodwill impairment charge relating to our Viridity business, the $5.0 million termination fee of the Galena 2 PPA, and the increase in general and administrative expenses, partially offset by an income of $7.2 million insurance settlement of our Puna power plant rig in the year ended December 31, 2018, as described above.

Income Taxes

Income tax provision for the year ended December 31, 2018, was $34.7 million, an increase of $13.0 million compared to an income tax provision of $21.7 million for the year ended December 31, 2017. The increase in income tax provision primarily resulted from the tax on global intangible low-tax income (GILTI), partially offset by a decrease in withholding tax on distribution of earnings, and the exclusion of other impacts of U.S. federal tax reform that resulted in a one-time tax impact for the year ended December 31, 2017. Our effective tax rate for the years ended December 31, 2018 and 2017, was 25.3% and 12.7%, respectively. Our effective tax rate at December 31, 2018 is principally based upon the composition of the income in different countries, tax on GILTI, accounting for intra-entity transfers of assets other than inventory, and changes related to valuation allowances. Our aggregate effective tax rate is higher than the 21% U.S federal statutory tax rate due to: (i) the impact of the newly enacted GILTI; (ii) higher tax rate in Kenya of 37.5% and Guadeloupe of 33.33% partially offset by a lower tax rate in Israel of 16 %; and (iii) withholding taxes on future distributions (see Note 18 - Income Taxes to the consolidated financial statements set forth in Item 8 of this annual report for further details regarding our income tax provision and the Tax Act).

For the years ended December 31, 2018 and 2017, we recorded a valuation allowance in the amount of approximately $22.4 million and $77.6 million, respectively, against our unutilized tax credits (FTCs and PTCs) and U.S. deferred tax assets related to state net operating loss (NOL) carryforwards. As of December 31, 2018, we had U.S. federal NOLs in the amount of approximately $230.5 million, state NOLs in the amount of approximately $269.1 million, and unutilized federal tax credits of approximately $149.0 million, some of which can be carried forward for 10-20 years. In addition, we had unutilized state tax credits of approximately 0.8 million, which can be carried forward for indefinite period. The related deferred tax assets totaled approximately $192.4 million after valuation allowance. Realization of these deferred tax assets and tax credits is dependent on generating sufficient taxable income in the United States prior to expiration of the NOL carryforwards and tax credits. The scheduled reversal of deferred tax liabilities, projected future taxable income, estimated impacts of tax reform and tax planning strategies were considered in determining the amount of valuation allowance. A valuation allowance in the amount of $22.4 million was recorded against the U.S. deferred tax assets as of December 31, 2018 because we believe it is more likely than not that the deferred tax assets will not be realized. If sufficient additional evidence of our ability to generate taxable income is established, we may be required to reduce or fully release the valuation allowance, resulting in income tax benefits in our consolidated statement of operations.

On December 22, 2017, the U.S. government signed into law the Tax Act. The Tax Act makes significant changes to the U.S. tax code, including, but not limited to, (1) reducing the U.S. federal corporate income tax rate from 35 percent to 21 percent; (2) the transition of U.S. international taxation from a worldwide tax system to a territorial system (GILTI, BEAT, Dividends Received Deduction); (3) one-time transition tax on undistributed earnings of foreign subsidiaries as of December 31, 2017; (4) eliminating the corporate alternative minimum tax (5) creating a new limitation on deductible interest expense; and (6) changing rules related to uses and limitations of net operating loss carryforwards created in tax years beginning after December 31, 2017.

We applied the guidance of SAB 118 for the effects of the Tax Act in 2017 and throughout 2018. The Deemed Repatriation Tax (Transition Tax) is a tax on previously untaxed accumulated and current earnings and profits (E&P) of certain foreign subsidiaries. To determine the amount of the Transition Tax, we determined, in addition to other factors, the amount of post-1986 E&P of the relevant subsidiaries, as well as the amount of non-U.S. income taxes paid on such earnings. As a result of our initial analysis of the impact of the Tax Act, we recorded a provisional amount of $71.6 million (gross) with respect to the inclusion of the transition tax at December 31, 2017. In addition, at December 31, 2017, we recorded a provisional benefit of $22.6 million relating to the remeasurement of deferred taxes from 35% to 21%.

As of December 31, 2018, we have completed our accounting for the tax effects of the Tax Reform Act. Subsequent adjustments to these amounts resulted in a reduction of $7.8 million to the transition tax and a decreased tax benefit of $3.5 million to the remeasurement of deferred taxes.

Under the Tax Act, the deductibility of net interest for a business is limited to 30% of adjusted taxable income. The new proposed regulations issued by Treasury applies regardless of whether the interest payment is made to a U.S. or foreign person, whether the interest recipient is related, or whether the interest recipient is exempt from U.S. tax. Further, any interest that cannot be deducted in a year can be carried forward indefinitely. We have not early adopted these proposed regulations and intend to adopt them during the 2019 tax year. For the year ended December 31, 2018, we have evaluated the impact and determined there is no limit on our interest deductibility for federal income tax purposes for the current period, but anticipates there could be significant limitations upon adoption.

We are also required to elect to either treat taxes due on future GILTI inclusions in United States taxable income as a current period expense when incurred or reflect such portion of the future GILTI inclusions in United States taxable income that relate to existing basis differences in our current measurement of deferred taxes. We have elected to treat the taxes due on future U.S. inclusions in taxable income under GILTI as a period cost when incurred. We have elected and applied the tax law ordering approach when considering GILTI as part of our valuation allowance.

We continue to monitor the impact of any additional guidance issued by Treasury. Notwithstanding the reduction in the corporate income tax rate, the overall impact of the Tax Act is uncertain, and our business, financial condition, future results and cash flow, as well as our stock price, could be adversely affected.

Equity in Earnings (losses) of Investees, Net

Equity in earnings (losses) of investees, net in the year ended December 31, 2018 was a profit of $7.7 million, compared to a loss of $2.0 million in the year ended December 31, 2017. Equity in earnings (losses) of investees, net derived from our 12.75% share in the losses of the Sarulla complex and from profits elimination.The increase was mainly attributable to utilization of carryforward losses and full year of commercial operations of SIL and NIL 1 and commercial operation of NIL 2 from May 2018.

Net Income

Net income for the year ended December 31, 2018 was $110.1 million, compared to $147.1 million for the year ended December 31, 2017, representing a decrease of $37.0 million from the prior period. This decrease in net income was primarily attributable to a decrease in operating income of $19.9 million, an increase of $16.8 million in interest expense, net and a decrease of $7.4 million in derivatives and foreign currency transaction gains and $13.1 million increase in income tax provision, partially offset due to an increase in Other non-operating income, net of $9.4 million, and an increase in equity in earnings of investees, net of $9.6 million, all as discussed above.

Net Income attributable to the Company's Stockholders

Net income attributable to the Company's stockholders for the year ended December 31, 2018 was $98.0 million, compared to $132.4 million for the year ended December 31, 2017, which represents a decrease of $34.4 million. This decrease was attributable to the decrease in net income of $37.0 million, offset partially by a decrease of $2.6 million in net income attributable to noncontrolling interest mainly due to the shutdown of the Puna power plant in Hawaii, all as discussed above.

Liquidity and Capital Resources

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

As of December 31, 2019, we had access to: (i) $71.2 million in cash and cash equivalents, of which $59.2 million was held by our foreign subsidiaries; and (ii) $213.9 million of unused corporate borrowing capacity under existing lines of credit with different commercial banks.

Our estimated capital needs for 2020 include approximately $332 million for capital expenditures on new projects under development or construction including storage projects, exploration activity and maintenance capital expenditures for our existing projects. In addition, we expect $135.5 million for long-term debt repayments, which excludes $50.0 million of commercial papers and approximately $40.6 million for revolver that we assume will be renewed.

As of December 31, 2019, $213.8 million in the aggregate was outstanding under credit agreements with several banks as detailed below under "Credit Agreements".

We expect to finance these requirements with: (i) the sources of liquidity described above; (ii) positive cash flows from our operations; and (iii) future project financings and re-financings (including construction loans and tax equity). Management believes that, based on the current stage of implementation of our strategic plan, the sources of liquidity and capital resources described above will address our anticipated liquidity, capital expenditures, and other investment requirements.

During 2019, we have revised our assertion to no longer indefinitely reinvest foreign funds held by our foreign subsidiaries, with the exception of a certain balance held in Israel and have accrued the incremental foreign withholding taxes. As a result, we have further liquidity to move funds freely.

Third-Party Debt

Our third-party debt consists of (i) non-recourse and limited-recourse project finance debt or acquisition financing that we or our subsidiaries have obtained for the purpose of developing and constructing, refinancing or acquiring our various projects and (ii) full-recourse debt incurred by us or our subsidiaries for general corporate purposes.

Non-Recourse and Limited-Recourse Third-Party Debt

Loan	Issued Amount ($M)	Outstanding Amount as of December 31, 2019	Interest Rate	Maturity Date	Related Projects	Location
OFC 2 Senior Secured Notes – Series A	151.7	94.3	4.82%	2032	McGinness Hills phase 1 and Tuscarora	United States
OFC 2 Senior Secured Notes – Series B	140.0	108.8	4.61%	2032	McGinness Hills phase 2	United States
Olkaria III Financing Agreement with OPIC – Tranche 1	85.0	51.9	6.34%	2030	Olkaria III Complex	Kenya
Olkaria III Financing Agreement with OPIC – Tranche 2	180.0	111.2	6.29%	2030	Olkaria III Complex	Kenya
Olkaria III Financing Agreement with OPIC – Tranche 3	45.0	29.6	6.12%	2030	Olkaria III Complex	Kenya
Amatitlan Financing [(1)]	42.0	26.3	LIBOR+4.35%	2027	Amatitlan	Guatemala
Don A. Campbell Senior Secured Notes	92.5	78.2	4.03%	2033	Don A. Campbell Complex	United States
Prudential Capital Group Idaho Loan [(2)]	20.0	18.3	5.8%	2023	Neal Hot Springs and Raft River	United States
U.S. Department of Energy loan [(3)]	96.8	44.9	2.61%	2035	Neal Hot Springs	United States
Prudential Capital Group Nevada Loan	30.7	27.1	6.75%	2037	San Emidio	United States
Platanares Loan with OPIC	114.7	104.5	7.02%	2032	Platanares	Honduras
Viridity – Plumstriker	23.5	21.6	LIBOR+3.5%	2026	Plumsted+Striker	United States
Geothermie Bouillante [(4)]	8.9	8.4	1.52%	2026	Geothermie Bouillante	Guadeloupe
Geothermie Bouillante [(4)]	8.9	9.0	1.93%	2026	Geothermie Bouillante	Guadeloupe
Total	**1,039.7**	**734.1**				

(1) LIBOR Rate cannot be lower than 1.25%. Margin of 4.35% as long as the Company's guaranty of the loan is outstanding (current situation) or 4.75% otherwise. Current interest is 6.29%.
(2) Secured by equity interest.
(3) Secured by the assets.
(4) Loan in Euros and issued amount is EUR 8.0 million

Full-Recourse Third-Party Debt

Loan	Issued Amount ($M)	Outstanding as of December 31, 2019	Interest Rate	Maturity Date
Senior Unsecured Bonds Series 2	67.2	67.2	3.7%	September 2020
Senior Unsecured Bonds Series 3	137.1	137.1	4.45%	September 2022
Commercial Paper[(1)]	50.0	50.0	3 month LIBOR+0.75%	[(2)]
Short term revolving credit lines with banks		40.6		
Senior unsecured Loan 1	100.0	100.0	4.8%	March 2029
Senior unsecured Loan 2	50.0	50.0	4.6%	March 2029
DEG Loan 2	50.0	42.5	6.28%	June 2028
DEG Loan 3	41.5	37.1	6.04%	June 2028
Total	**495.8**	**524.5**		

(1) Current interest rate is 2.69%.
(2) Issued for 90 days and extends automatically for additional periods of 90 days each for up to five years.

Letters of Credits under the Credit Agreements

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.

Credit Agreements	Issued Amount ($M)	Issued and Outstanding as of December 31, 2019	Termination Date
MUFG	60.0	59.5	June 2020
HSBC	35.0	25.5	October 2020
Other Institutions	260.0	15.6	March 2020 – July 2022
Other Banks 1	150.0	103.1	September 2020 – July 2022
Other Banks 2	-	10.1	December 2020
Total	**505.0**	**213.8**	

Restrictive covenants

Our obligations under the credit agreements, the loan agreements, and the trust instrument governing the bonds described above, are unsecured, but we are subject to a negative pledge in favor of the banks and the other lenders and certain other restrictive covenants. These include, among other things, a prohibition on: (i) creating any floating charge or any permanent pledge, charge or lien over our assets without obtaining the prior written approval of the lender; (ii) guaranteeing the liabilities of any third party without obtaining the prior written approval of the lender; and (iii) selling, assigning, transferring, conveying or disposing of all or substantially all of our assets, or a change of control in our ownership structure. Some of the credit agreements, the term loan agreements, and the trust instrument contain cross-default provisions with respect to other material indebtedness owed by us to any third party. In some cases, we have agreed to maintain certain financial ratios, which are measured quarterly, such as: (i) equity of at least $600 million and in no event less than 25% of total assets; (ii) 12-month debt, net of cash, cash equivalents, and short-term bank deposits to Adjusted EBITDA ratio not to exceed 6.0; and (iii) dividend distributions not to exceed 35% of net income in any calendar year. As of December 31, 2019: (i) total equity was $1,515.4 million and the actual equity to total assets ratio was 46.6% and (ii) the 12-month debt, net of cash, cash equivalents, to Adjusted EBITDA ratio was 2.99. During the year ended December 31, 2019, we distributed interim dividends in an aggregate amount of $22.4 million. The failure to perform or observe any of the covenants set forth in such agreements, subject to various cure periods, would result in the occurrence of an event of default and would enable the lenders to accelerate all amounts due under each such agreement.

As described above, we are currently in compliance with our covenants with respect to the credit agreements, the loan agreements and the trust instrument, and believe that the restrictive covenants, financial ratios and other terms of any of our full-recourse bank credit agreements will not materially impact our business plan or operations.

Future minimum payments

Future minimum payments under long-term obligations, excluding revolving credit lines with commercial banks, as of December 31, 2019, are detailed under the caption Contractual Obligations and Commercial Commitments, below.

Puna Power Plant Lease Transactions

In May 2005, our Hawaiian subsidiary, PGV, entered into lease transactions involving the original geothermal power plant of the Puna Complex located on the Big Island (the Puna Power Plant).

In connection with the execution of the new amended and restated PPA described under "Recent Developments" above, we paid $20.5 million to effectively terminate the lease transactions (the amount includes all future payments according to the original lease agreements) involving the original power plant in order to enter into and meet our obligations under the new PPA. As a result, we have no obligation for future minimum lease payments as of December 31, 2019.

Liquidity Impact of Uncertain Tax Positions

As discussed in Note 18 - Income Taxes, to our consolidated financial statements set forth in Item 8 of this annual report, we have a liability associated with unrecognized tax benefits and related interest and penalties in the amount of approximately $14.6 million as of December 31, 2019. 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 12 months. We are not able to reasonably estimate when we will make any cash payments required to settle this liability.

Dividends

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

Date Declared	Dividend Amount per Share	Record Date	Payment Date
March 1, 2018	$ 0.23	March 14, 2018	March 29, 2018
May 7, 2018	$ 0.10	May 21, 2018	May 30, 2018
August 7, 2018	$ 0.10	August 21, 2018	August 29, 2018
November 6, 2018	$ 0.10	November 20, 2018	December 4, 2018
February 26, 2019	$ 0.11	March 14, 2019	March 28, 2019
May 6, 2019	$ 0.11	May 20, 2019	May 28, 2019
August 7, 2019	$ 0.11	August 20, 2019	August 27, 2019
November 6, 2019	$ 0.11	November 20, 2019	December 4, 2019
February 25, 2020	$ 0.11	March 12, 2020	March 26, 2020

Historical Cash Flows

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

	Year Ended December 31,		
	2019	2018	2017
	(Dollars in thousands)		
Net cash provided by operating activities	$ 236,493	$ 145,822	$ 245,575
Net cash used in investing activities	(254,538)	(342,434)	(345,526)
Net cash provided by (used in) financing activities	(5,765)	251,131	(67,882)
Translation adjustments on cash and cash equivalents	(575)	(660)	—
Net change in cash and cash equivalents and restricted cash and cash equivalents	$ (24,385)	$ 53,859	$ (167,833)

For the Year Ended December 31, 2019

Net cash provided by operating activities for the year ended December 31, 2019 was $236.5 million, compared to $145.8 million for the year ended December 31, 2018. This increase of $99.1 million resulted primarily from (i) an increase in accounts payable and accrued expenses of $8.7 million in the year ended December 31, 2019, compared to a decrease of $56.7 million in the year ended December 31, 2018, driven by: (i) a withholding tax payment of approximately $14 million in the year ended December 31, 2019 compared to $44 million in the year ended December 31, 2018, because of a distribution from OSL (ii) the timing of payments to our suppliers and (iii) a decrease of $15.1 million in receivables in the year ended December 31, 2019 compared to $29.9 million in the year ended December 31, 2018 because of timing of collections from our customers.

Net cash used in investing activities for the year ended December 31, 2019 was $254.5 million, compared to $342.4 million for the year ended December 31, 2018. The principal factors that affected our net cash used in investing activities during the year ended December 31, 2019 were: (i) capital expenditures of $280.0 million, primarily for our facilities under construction; and (ii) an investment in an unconsolidated company of $10.7 million, partially offset by proceeds from insurance recoveries of $35.4 million.

Net cash used in financing activities for the year ended December 31, 2019 was $5.8 million, compared to $251.1 million provided by financing activities for the year ended December 31, 2018. The principal factors that affected the net cash used in financing activities during the year ended December 31, 2019 were: (i) net payment of $118.5 million from our revolving credit lines with commercial banks which were used for capital expenditures, (ii) the repayment of long-term debt in the amount of $93.8 million; (iii) a $22.4 million cash dividend payment and (iv) $9.7 million cash paid to a noncontrolling interest, partially offset by, (i) $50 million of proceeds from a senior unsecured loan, (ii) $41.5 million of proceeds from a term loan for our Olkaria III Complex plant 1 expansion, (iii) $23.5 million of proceeds for the financing of two 20 MW battery energy storage projects, (iv) $17.8 million of proceeds from limited and non-recourse loans for our Guadeloupe power plant, (v) $50.0 million of proceeds from issuance of commercial paper and (vi) proceeds from the sale of a limited liability company interest in McGinness Hills Phase 3, net of transaction costs of $58.3 million.

For the Year Ended December 31, 2018

Net cash provided by operating activities for the year ended December 31, 2018 was $145.8 million, compared to $245.6 million for the year ended December 31, 2017. This decrease of $99.8 million resulted primarily from a decrease in accounts payable and accrued expenses of $56.7 million in the year ended December 31, 2018, compared to an increase of $51.6 million in the year ended December 31, 2017, mainly due to a withholding tax payment of approximately $44 million due to a distribution from OSL, offset partially by approximately $14 million due to a distribution from OSL in 2018. The decrease was also due to timing of payments to our suppliers.

Net cash used in investing activities for the year ended December 31, 2018 was $342.4 million, compared to $345.5 million for the year ended December 31, 2017. The principal factors that affected our net cash used in investing activities during the year ended December 31, 2018 were: (i) capital expenditures of $258.5 million, primarily for our facilities under construction; (ii) cash paid for acquisition of controlling interest in USG, net of cash acquired of $95.1 million; and (iii) an investment in an unconsolidated company of $3.8 million.

Net cash used in financing activities for the year ended December 31, 2018 was $251.1 million, compared to $67.9 million provided by financing activities for the year ended December 31, 2017. The principal factors that affected the net cash provided by financing activities during the year ended December 31, 2018 were: (i) $100.0 million of proceeds from a senior unsecured loan, (ii) $114.7 million of proceeds from a limited and non-recourse loan; (iii) net proceeds of $107.5 million from our revolving credit lines with commercial banks which were used for capital expenditures, and (iv) proceeds from the sale of a limited liability company interest in Tungsten, net of transaction costs of $32.2 million, partially offset by: (i) the repayment of long-term debt in the amount of $62.8 million; (ii) a $26.8 million cash dividend paid; and (iii) $13.1 million of cash paid to noncontrolling interests.

Total EBITDA and Adjusted EBITDA

We calculate EBITDA as net income before interest, taxes, depreciation and amortization. We calculate Adjusted EBITDA as net income before interest, taxes, depreciation and amortization, adjusted for (i) termination fees, (ii) impairment of long-lived assets, (iii) write-off of unsuccessful exploration activities, (iv) any mark-to-market gains or losses from accounting for derivatives, (v) merger and acquisition transaction costs, (vi) stock-based compensation, (vii) gain or loss from extinguishment of liabilities, (viii) gain or loss on sale of subsidiary and property, plant and equipment and (ix) other unusual or non-recurring items. EBITDA and Adjusted EBITDA are not measurements of financial performance or liquidity under accounting principles generally accepted in the United States, or U.S. GAAP, and should not be considered as an alternative to cash flow from operating activities or as a measure of liquidity or an alternative to net earnings as indicators of our operating performance or any other measures of performance derived in accordance with U.S. GAAP. We use EBITDA and Adjusted EBITDA as a performance metric because it is a metric used by our Board of Directors and senior management in evaluating our financial performance. However, other companies in our industry may calculate EBITDA and Adjusted EBITDA differently than we do.

This information should not be considered in isolation from, or as a substitute for, or superior to, measures of financial performance prepared in accordance with GAAP or other non-GAAP financial measures.

Adjusted EBITDA for the year ended December 31, 2019 was $384.3 million, compared to $368.0 million for the year ended December 31, 2018 and $343.8 million for the year ended December 31, 2017.

The following table reconciles net income to EBITDA and adjusted EBITDA for the years ended December 31, 2019, 2018 and 2017:

	Year Ended December 31,		
	2019	**2018**	**2017**
	(Dollars in thousands)		
Net income	$ 93,543	$ 110,111	$ 147,109
Adjusted for:			
Interest expense, net (including amortization of deferred financing costs)	78,869	69,950	53,154
Income tax provision (benefit)	45,613	34,733	21,664
Adjustment to investment in an unconsolidated company: our proportionate share in interest expense, tax and depreciation and amortization in Sarulla complex	13,089	9,184	(265)
Depreciation and amortization	143,242	127,732	108,693
EBITDA	**374,356**	**351,710**	**330,355**
Mark-to-market on derivative instruments	(1,402)	2,032	(1,500)
Stock-based compensation	9,358	10,218	8,760
Insurance proceeds in excess of assets carrying value	—	(7,150)	—
Termination fee	—	3,142	—
Impairment of goodwill, net of reversal of a contingent liability	—	4,973	—
Loss from extinguishment of liability	468	—	1,950
Merger and acquisition transaction costs	1,483	2,910	2,460
Write-off of unsuccessful exploration activities	—	126	1,796
Adjusted EBITDA	**$ 384,263**	**$ 367,961**	**$ 343,821**

Adjusted EBITDA excluding the impact of Puna related expenses of approximately $1.2 million for the year ended December 31, 2019 is $385.5 million.

EBITDA includes the proportionate share (12.75%) of net depreciation, interest and tax expenses from our unconsolidated investment in the Sarulla complex that is accounted for under the equity method.

On May 2014, the Sarulla consortium ("SOL") closed $1,170 million in financing. As of December 31, 2019, the credit facility has an outstanding balance of $1,074.2 million. Our proportionate share in the SOL credit facility is $137.0 million.

Capital Expenditures

Our capital expenditures primarily relate to the enhancement of our existing power plants and the exploration, development and construction of new power plants.

We have budgeted approximately $359 million in capital expenditures for construction of new projects and enhancements to our existing power plants, of which we had invested $96.2 million as of December 31, 2019. We expect to invest approximately $134 million in 2020 and the remaining approximately $128 million thereafter.

In addition, we estimate approximately $198 million in additional capital expenditures in 2020 to be allocated as follows: (i) approximately $57 million for the exploration and development of new projects and enhancements of existing power plants that not yet released for full construction (ii) approximately $61 million for maintenance of capital expenditures to our operating power plants including drilling in our Puna power plant; (iii) approximately $65 million for the construction and development of storage projects; and (iv) approximately $15.0 million for enhancements to our production facilities.

In the aggregate, we estimate our total capital expenditures for 2020 to be approximately $332 million.

Exposure to Market Risks

Based on current conditions, we believe that we have sufficient financial resources to fund our activities and execute our business plans. However, the cost of obtaining financing for our project needs may increase significantly or such financing may be difficult to obtain.

We, like other power plant operators, are exposed to electricity price volatility risk. Our exposure to such market risk is currently limited because many of our long-term PPAs (except for the 25 MW PPA for the Puna Complex and the between 30 MW and 40 MW PPAs in the aggregate for the Heber 2 power plant in the Heber Complex and the G2 power plant in the Mammoth Complex) have fixed or escalating rate provisions that limit our exposure to changes in electricity prices. The energy payments under the PPAs of the Heber 2 power plant in the Heber Complex and the G2 power plant in Mammoth Complex are determined by reference to the relevant power purchaser's SRAC. A decline in the price of natural gas will result in a decrease in the incremental cost that the power purchaser avoids by not generating its electrical energy needs from natural gas, or by reducing the price of purchasing its electrical energy needs from natural gas power plants, which in turn will reduce the energy payments that we may charge under the relevant PPA for these power plants. The Puna Complex is currently benefiting from energy prices which are higher than the floor under the 25 MW PPA for the Puna Complex as a result of the high fuel costs that impact HELCO's avoided costs.

As of December 31, 2019, 95.9% of our consolidated long-term debt was fixed rate debt and therefore was not subject to interest rate volatility risk and 4.1% of our long-term debt was floating rate debt, exposing us to interest rate risk in connection therewith. As of December 31, 2019, $47.9 million of our long-term debt remained subject to some interest rate risk.

We currently maintain our surplus cash in short-term, interest-bearing bank deposits, money market securities and commercial paper with a minimum investment grade rating of AA by Standard & Poor's Ratings Services.

Our cash equivalents are subject to interest rate risk. Fixed rate securities may have their market value adversely impacted by a rise in interest rates, while floating rate securities may produce less income than expected if interest rates fall. As a result of these factors, our future investment income may fall short of expectations because of changes in interest rates, or we may suffer losses in principal if we are forced to sell securities that decline in market value because of changes in interest rates.

We are also exposed to foreign currency exchange risk, in particular the fluctuation of the U.S. dollar versus the NIS in Israel and KES in Kenya. Risks attributable to fluctuations in currency exchange rates can arise when we or any of our foreign subsidiaries borrow funds or incur operating or other expenses in one type of currency but receive revenues in another. In such cases, an adverse change in exchange rates can reduce such subsidiary's ability to meet its debt service obligations, reduce the amount of cash and income we receive from such foreign subsidiary, or increase such subsidiary's overall expenses. In Kenya, the tax asset is recorded in KES similar to the tax liability, however any change in the exchange rate in the KES versus the USD has an impact on our financial results. Risks attributable to fluctuations in foreign currency exchange rates can also arise when the currency denomination of a particular contract is not the U.S. dollar. Substantially all of our PPAs in the international markets are either U.S. dollar-denominated or linked to the U.S. dollar except for our operations on Guadeloupe, where we own and operate the Boulliante power plant which sells its power under a Euro-denominated PPA with Électricité de France S.A. Our construction contracts from time to time contemplate costs which are incurred in local currencies. The way we often mitigate such risk is to receive part of the proceeds from the contract in the currency in which the expenses are incurred. Currently, we have forward contracts in place to reduce our foreign currency exposure and expect to continue to use currency exchange and other derivative instruments to the extent we deem such instruments to be the appropriate tool for managing such exposure. In the three months ended December 31, 2019, our exchange rate exposure in Kenya resulted in an expense of approximately $2.5 million.

We performed a sensitivity analysis on the fair values of our long-term debt obligations, and foreign currency exchange forward contracts. The foreign currency exchange forward contracts listed below principally relate to trading activities. The sensitivity analysis involved increasing and decreasing forward rates at December 31, 2019 and 2018 by a hypothetical 10% and calculating the resulting change in the fair values.

At this time, the development of our new strategic plan has not exposed us to any additional market risk. However, as the implementation of the plan progresses, we may be exposed to additional or different market risks.

The results of the sensitivity analysis calculations as of December 31, 2019 and 2018 are presented below:

	Assuming a 10% Increase in Rates		Assuming a 10% Decrease in Rates		
	As of December 31,		As of December 31,		
Risk	**2019**	**2018**	**2019**	**2018**	**Change in the Fair Value of**
	(In thousands)				
Foreign Currency	$ (4,198)	$ (4,042)	$ 5,131	$ 4,940	Foreign Currency Forward Contracts
Interest Rate	$ —	$ (113)	$ —	$ 114	OrCal Senior Secured Notes
Interest Rate	$ (4,574)	$ (5,955)	$ 4,723	$ 6,211	OFC 2 Senior Secured Notes
Interest Rate	$ (4,647)	$ (6,022)	$ 4,812	$ 6,294	OPIC Loan
Interest Rate	$ (516)	$ (714)	$ 534	$ 745	Amatitlan loan
Interest Rate	$ (1,797)	$ (3,054)	$ 1,822	$ 3,118	Senior Unsecured Bonds
Interest Rate	$ (905)	$ (1,216)	$ 934	$ 1,266	DEG 2 Loan
Interest Rate	$ (1,835)	$ (2,324)	$ 1,906	$ 2,438	DAC 1 Senior Secured Notes
Interest Rate	$ (3,272)	$ (2,897)	$ 3,363	$ 3,010	Migdal Loan and the Additional Migdal Loan
Interest Rate	$ (1,141)	$ (1,306)	$ 1,207	$ 1,398	San Emidio Loan
Interest Rate	$ (776)	$ (1,153)	$ 797	$ 1,197	DOE Loan
Interest Rate	$ (281)	$ (440)	$ 286	$ 453	Idaho Holdings Loan
Interest Rate	$ (2,978)	$ (3,719)	$ 3,099	$ 3,907	Platanares OPIC Loan
Interest Rate	$ (728)	$ —	$ 749	$ —	DEG 3 Loan
Interest Rate	$ (342)	$ —	$ 350	$ —	Plumstriker Loan
Interest Rate	$ (295)	$ —	$ 298	$ —	Commercial Paper
Interest Rate	$ (201)	$ (143)	$ 204	$ 148	Other long-term loans

In July 2019, the United Kingdom's Financial Conduct Authority, which regulates LIBOR (London Interbank Offered Rate), announced that it intends to phase out LIBOR by the end of 2021. It is unclear whether or not LIBOR will cease to exist at that time and/or whether new methods of calculating LIBOR will be established such that it will continue to exist after 2021. The U.S. Federal Reserve, in conjunction with the Alternative Reference Rates Committee, a steering committee comprised of large U.S. financial institutions, is considering replacing U.S. dollar LIBOR with a new SOFR (Secured Overnight Financing Rate) index calculated by short-term repurchase agreements, backed by Treasury securities.

We have evaluated the impact of the transition from LIBOR, and currently believe that the transition will not have a material impact on our consolidated financial statements.

Effect of Inflation

We expect that inflation will not be a significant risk in the near term, given the current global economic conditions, however, that could change in the future. To address rising inflation some of our contracts include certain provisions that mitigate inflation risk.

In connection with the Electricity segment, none of our U.S. PPAs, including the SCPPA Portfolio PPA, are directly linked to the CPI. Inflation may directly impact an expense we incur for the operation of our projects, thereby increasing our overall operating costs and reducing our profit and gross margin. The negative impact of inflation would be partially offset by price adjustments built into some of our PPAs that could be triggered upon such occurrences. The energy payments pursuant to our PPAs for some of our power plants such as the Brady power plant, the Steamboat 2 and 3 power plants and the McGinness Complex, increase every year through the end of the relevant terms of such agreements, although such increases are not directly linked to the CPI or any other inflationary index. Lease payments are generally fixed, while royalty payments are generally calculated as a percentage of revenues and therefore are not significantly impacted by inflation. In our Product segment, inflation may directly impact fixed and variable costs incurred in the construction of our power plants, thereby increasing our operating costs in the Product segment. We are more likely to be able to offset all or part of this inflationary impact through our project pricing. With respect to power plants that we build for our own electricity production, inflationary pricing may impact our operating costs which may be partially offset in the pricing of the new long-term PPAs that we negotiate.

Contractual Obligations and Commercial Commitments

The following tables set forth our material contractual obligations as of December 31, 2019 (in thousands):

		Payments Due by Period					
	Remaining Total	2020	2021	2022	2023	2024	Thereafter
Long-term liabilities principal	$ 1,167,912	$ 135,504	$ 76,259	$ 220,677	$ 98,982	$ 78,600	$ 557,890
Interest on long-term liabilities [1]	336,593	58,555	52,228	47,931	44,593	32,061	101,225
Finance lease obligations	19,854	4,251	3,948	3,873	2,758	906	4,118
Operating lease obligations	20,956	2,742	2,701	2,079	1,524	1,275	10,635
Benefits upon retirement [2]	19,803	4,780	1,434	1,768	89	500	11,232
Asset retirement obligation	50,183	—	—	—	—	—	50,183
Purchase commitments [3]	184,985	184,985	—	—	—	—	—
	$ 1,800,286	$ 390,817	$ 136,570	$ 276,328	$ 147,946	$ 113,342	$ 735,283

(1) See interest rates and maturity dates under Liquidity and Capital Resources section above.

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

(3) We purchase raw materials for inventories, construction-in-process and services from a variety of vendors. During the normal course of business, in order to manage manufacturing lead times and help assure adequate supply, we enter into agreements with contract manufacturers and suppliers that either allow them to procure goods and services based upon specifications defined by us, or that establish parameters defining our requirements. At December 31, 2019, total obligations related to such supplier agreements were approximately $185.0 million (approximately $59.5 million of which relate to construction-in-process). All such obligations are payable in 2020.

The table above does not reflect unrecognized tax benefits of $14.6 million, the timing of which is uncertain. Refer to Note 18 to our consolidated financial statements set forth in Item 8 of this annual report for additional discussion of unrecognized tax benefits. The above table also does not reflect a liability associated with the sale of tax benefits of $123.5 million, the timing of which is uncertain and other long-term liabilities of $6.8 million that are deemed immaterial. Refer to Note 13 to our consolidated financial statements as set forth in Item 8 of this annual report for additional discussion of our liability associated with the sale of tax benefits.

Concentration of Credit Risk

Our credit risk is currently concentrated with the following major customers: Sierra Pacific Power Company and Nevada Power Company (subsidiaries of NV Energy), KPLC and SCPPA. If any of these electric utilities fail to make payments under its PPAs with us, such failure would have a material adverse impact on our financial condition. Also, by implementing our multi-year strategic plan we may be exposed, by expanding our customer base, to different credit profile customers than our current customers.

Sierra Pacific Power Company and Nevada Power Company accounted for 17.1%, 16.1% and 18.1% of our total revenues for the three years ended December 31, 2019, 2018 and 2017, respectively.

KPLC accounted for 16.3%, 16.6%, and 15.9% of our total revenues for the three years ended December 31, 2019, 2018 and 2017, respectively.

SCPPA accounted for 17.9%, 15.2% and 10.1% of our total revenues for the three years ended December 31, 2019, 2018 and 2017, respectively.

We have historically been able to collect on substantially all of our receivable balances. As of December 31, 2019, the amount overdue from KPLC in Kenya was $40.7 million of which $24.2 million was paid in January and February of 2020. These amounts are an average of 70 days overdue, an increase of 10 days from September 30, 2019. In Honduras, we began collecting current charges from ENEE in May 2019; however, as of December 31, 2019, the amount overdue relating to the period from October 2018 to April 2019 is $20.1 million, none of which has been paid to date. Due to obligations of the Honduran government to support us, we believe we will be able to collect all past due amounts.

Government Grants and Tax Benefits

The U.S. federal government encourages production of electricity from geothermal resources or solar energy through certain tax subsidies:

- PTC - the PTC rules provide an income tax credit for each kWh of electricity produced from certain renewable energy sources, including geothermal, and sold to an unrelated person during a taxable year. The PTC was first introduced in 1992 and has since been revised a number of times. The PTC, which in 2019 was 2.5 cents per kWh, is adjusted annually for inflation and may be claimed for 10 years on the net electricity output sold to third parties after the project is first placed in service. The tax extender package signed into law in December 2019 provides that any qualifying project that starts construction by December 31, 2020 would be eligible for PTC. The qualifying project must ordinarily be placed in service within four years after the end of the year in which construction started or show continued construction to qualify for PTC. The PTC is not available for power produced from geothermal resources for projects that started construction on or after January 1, 2021.

- ITC - the ITC rules have been amended a number of times. A qualified new geothermal power plant in the United States that starts construction by the end of 2020 would be eligible to claim an ITC of 30% of the project cost. New solar projects that were under construction by December 2019 will qualify for a 30% ITC. The credit will phasedown to 26% for solar PV projects starting construction in 2020 and to 22% for solar PV projects starting construction in 2021. Projects that were under construction before these deadlines must be placed in service by December 31, 2023 to qualify for the ITC at these rates. solar projects placed in service after December 31, 2023 will only qualify for a 10% ITC. Under current tax rules, any unused tax credit has a one-year carry back and a twenty-year carry forward.

- On December 22, 2017, the U.S. President signed into law the Tax Act, which made changes that have some impact on the renewable energy industry. Some of the key changes are as follows:
    - The U.S. corporate income tax rate was reduced from 35% to 21% beginning in 2018.
    - Bonus depreciation was increased from 40% expensing of qualified projects in year one to 100% beginning in on September 27, 2017. The 100% expensing is valid through 2022 and then declines through 2026.
    - The BEAT provision is a new tax intended to apply to companies that significantly reduce their U.S. tax liability by making cross-border payments to affiliates. The provision aims to circumvent earnings stripping by imposing a minimum tax of 10% of taxable income. ITC and PTC can be used to offset approximately 80% BEAT. See the discussion under Item 1A — “Risk Factors”.

We are also permitted to depreciate most of the cost of a new geothermal power plant. In cases where we claim the one-time 30% (or 10%) ITC, our tax basis in the plant that is eligible for depreciation is reduced by one-half of the ITC amount. In cases where we claim the PTC, there is no reduction in the tax basis for depreciation. Projects that were placed in service in 2016 and 2017 were eligible for "bonus" depreciation of 50% of the cost of that equipment in the year the power plant was placed in service. Following the Tax Act, projects that were or will be placed in service after September 27, 2017, could qualify for a 100% bonus depreciation with respect to its qualifying assets. After applying any depreciation bonus that is available, we can depreciate the remainder of our tax basis in the plant, if any, mostly 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. We will continue to analyze this new provision under the Act and determine if an election is appropriate as it relates to our business needs.

Ormat Systems received "Benefited Enterprise" status under Israel's Law for Encouragement of Capital Investments, 1959 (the Investment Law), with respect to two of its investment programs through 2011. In January 2011, new legislation amending the Investment Law was enacted. Under the new legislation, a uniform rate of corporate tax will apply to all qualified income of certain industrial companies, as opposed to the previous law's incentives that are limited to income from a "Benefited Enterprise" during their benefits period. As a result, we now pay a uniform corporate tax rate of 16% with respect to that qualified income.

Kenya tax audit

The Company received three letters from the Kenya Revenue Authority ("KRA") relating to certain findings in respect of its review of tax years 2013 to 2017 as described below:

The first Letter of Preliminary Findings was received in March 2019, which was followed by a Notice of Assessment during June 2019 in which the KRA demanded approximately $5.6 million from the Company, including interest and penalties in respect of two certain issues relating to its review of tax years 2014 to 2017. In July 2019, the Company responded to the KRA Notice of Assessment primarily objecting to one of the two issues raised in the assessment, consisting of approximately $4.4 million, and asked the KRA to vacate this issue as set forth in its tax assessment letter.

The Company received the second Letter of Preliminary Findings ("the Second Letter of Preliminary Findings") from the KRA in July 2019, which relates to findings from the KRA's audit review for tax years 2013 to 2017. In August 2019, the Company filed its response to the Second Letter of Preliminary Findings, contesting the KRA arguments and requesting that the KRA vacate all issues set forth in its Letter of Preliminary Findings. In December 2019, the KRA submitted its audit assessment letter in relation to the 2013 to 2017 tax years in which it demanded approximately $205 million from the Company, including interest and penalties in respect of the issues included in its Second Letter of Preliminary Findings. In January 2020, the Company responded to the KRA objecting to all the issues raised in the tax assessment for tax years 2013 to 2017 and asked the KRA to vacate all issues set forth in its tax assessment letter.

The Company received the third Letter of Preliminary Findings (the "Third Letter of Preliminary Findings") from the KRA in December 2019 relating to the same tax years in which the KRA set forth an additional demand for approximately $17 million, including interest and penalties, in relation to an additional audit finding which was not previously included in the KRA's assessments. In January 2020, the Company filed a formal objection to the Third Letter of Preliminary Findings, contesting the KRA's finding.

The Company is currently at different stages of discussions with the KRA on the matters included in the KRA letters of assessment and preliminary findings as described above and believes its tax positions for the issues raised during the audit period is more-likely-than-not sustainable based on technical merits under Kenyan tax law. As of December 31, 2019, the Company has not recorded any tax reserves related to these demands except for an immaterial amount included in the first Letter of Preliminary Findings.

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

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

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

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

Opinions on the Financial Statements and Internal Control over Financial Reporting

We have audited the accompanying consolidated balance sheets of Ormat Technologies, Inc. and its subsidiaries (the "Company") as of December 31, 2019 and 2018, and the related consolidated statements of operations and comprehensive income (loss), of equity and of cash flows for the years then ended, including the related notes (collectively referred to as the "consolidated financial statements"). We also have audited the Company's internal control over financial reporting as of December 31, 2019, based on criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 2019 and 2018, and the results of its operations and its cash flows for each of the years then ended in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company did not maintain, in all material respects, effective internal control over financial reporting as of December 31, 2019, based on criteria established in *Internal Control - Integrated Framework* (2013) issued by the COSO because a material weakness in internal control over financial reporting existed as of that date related to ineffective risk assessment over accounting for income taxes.

A material weakness is a deficiency, or a combination of deficiencies, in internal control over financial reporting, such that there is a reasonable possibility that a material misstatement of the annual or interim financial statements will not be prevented or detected on a timely basis. The material weakness referred to above is described in Management's Report on Internal Control over Financial Reporting appearing under Item 9A. We considered this material weakness in determining the nature, timing, and extent of audit tests applied in our audit of the 2019 consolidated financial statements, and our opinion regarding the effectiveness of the Company's internal control over financial reporting does not affect our opinion on those consolidated financial statements.

Basis for Opinions

The Company's management is responsible for these consolidated financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting included in management's report referred to above. Our responsibility is to express opinions on the Company's consolidated financial statements and on the Company's internal control over financial reporting based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud, and whether effective internal control over financial reporting was maintained in all material respects.

Our audits of the consolidated financial statements included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

Definition and Limitations of Internal Control over Financial Reporting

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

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

Critical Audit Matters

The critical audit matters communicated below are matters arising from the current period audit of the consolidated financial statements that were communicated or required to be communicated to the audit committee and that (i) relate to accounts or disclosures that are material to the consolidated financial statements and (ii) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the consolidated financial statements, taken as a whole, and we are not, by communicating the critical audit matters below, providing separate opinions on the critical audit matters or on the accounts or disclosures to which they relate.

Percentage of Completion Estimates in Product Revenue Recognition

As described in Note 19 to the consolidated financial statements, $191 million of the Company's total revenue for the year ended December 31, 2019 was generated from product revenue. As disclosed by management, product revenue is recognized using the percentage of completion method, which requires estimating future costs over the full term of product delivery. The percentage of completion method is used because management believes that measure best depicts the transfer of control to the customer, which occurs as the Company incurs costs on the contracts. Under the percentage of completion method, the extent of progress towards completion is based on the ratio of costs incurred to date to the total estimated costs at completion of the performance obligation. Revenue is recognized proportionately as costs are incurred. Such estimates of future costs are made by management based on prior historical contracts that have been completed and specific project characteristics. Due to the nature of the work performed to deliver the products, management's estimation of future costs requires significant judgment.

The principal consideration for our determination that performing procedures relating to percentage of completion estimates in product revenue recognition is a critical audit matter is that there was significant judgment by management when developing the estimates of future costs to complete projects. This in turn led to significant auditor judgment and effort in performing procedures to evaluate management's estimates of future costs to complete projects.

Addressing the matter involved performing procedures and evaluating audit evidence in connection with forming our overall opinion on the consolidated financial statements. These procedures included testing the effectiveness of controls relating to the revenue recognition process, including controls over the determination of estimates of future costs to complete projects. These procedures also included, among others, evaluating and testing management's process for determining the estimates of future costs for a sample of projects. Evaluating the reasonableness of significant assumptions involved evaluating management's ability to estimate future costs to complete projects by (i) performing a comparison of the originally estimated and actual costs incurred on similar completed projects; (ii) evaluating the timely identification of circumstances that may warrant a modification to estimated costs to complete projects, including changes in job performance, job conditions, and estimated profitability; and (iii) testing management's process for evaluating the Company's ability to execute the specific contract characteristics.

Realizability of Deferred Tax Assets

As described in Note 18 to the consolidated financial statements, the Company's deferred tax asset balance as of December 31, 2019 is $130 million. As disclosed by management, significant estimates are required to calculate the consolidated income tax provision and tax balances. Management calculates temporary differences resulting from differing treatments of items for tax and accounting purposes, which can result in the creation of deferred tax assets or liabilities. For those jurisdictions where the realization of net deferred tax assets is not more likely than not, a valuation allowance is recorded. In assessing the need for a valuation allowance, management estimates future taxable income by jurisdiction while also considering the feasibility of ongoing tax planning strategies and the realization of tax credits and net operating loss carryforwards. Significant estimates are required in estimating future taxable income by jurisdiction, leading to significant judgment from management.

The principal consideration for our determination that performing procedures relating to the realizability of deferred tax assets is a critical auditor matter is that there was significant judgment by management in estimating future taxable income by jurisdiction. This in turn led to significant auditor judgment and effort in performing procedures to evaluate management's estimates of future taxable income.

Addressing the matter involved performing procedures and evaluating audit evidence in connection with forming our overall opinion on the consolidated financial statements. These procedures included testing the effectiveness of controls relating to the income tax process, including controls over estimating future taxable income by jurisdiction in order to assess the realizability of deferred tax assets. These procedures also included, among others, testing management’s process for assessing the realizability of deferred tax assets, testing the completeness and accuracy of underlying data used in management’s assessment and evaluating the reasonableness of management’s assumptions related to estimating future taxable income. Evaluating management’s assumptions related to estimating future taxable income involved evaluating whether the assumptions used by management were reasonable considering (i) the current and past performance of the Company; (ii) the consistency with external market and industry data; and (iii) the consistency of the assumptions with evidence obtained in other areas of the audit.

/s/ Kesselman & Kesselman
Certified Public Accountants (Isr.)
A member firm of PricewaterhouseCoopers International Limited

Tel Aviv, Israel
March 2, 2020

We have served as the Company’s auditor since 2018.

Report of Independent Registered Public Accounting Firm

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

Opinion on the Financial Statements

We have audited the accompanying consolidated statements of operations and comprehensive income (loss), of equity and cash flows of Ormat Technologies, Inc. and its subsidiaries (the "Company") for the year ended December 31, 2017, including the related notes (collectively referred to as the "consolidated financial statements"). In our opinion, the consolidated financial statements present fairly, in all material respects, the results of operations and cash flows of the Company for the year ended December 31, 2017 in conformity with accounting principles generally accepted in the United States of America.

Basis for Opinion

These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's consolidated financial statements based on our audit. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit of these consolidated financial statements in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud.

Our audit included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audit also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. We believe that our audit provides a reasonable basis for our opinion.

/s/ PricewaterhouseCoopers LLP

San Francisco, California

March 16, 2018, except for the effects of the restatement and revision discussed in Note 1 (not presented herein) to the consolidated financial statements appearing under Item 8 of the Company's 2017 annual report on Form 10-K/A, as to which the date is June 19, 2018, and except for the effects of the retrospective adjustments as a result of adoption of accounting policies and changes in segments as discussed in Note 1(a) (not presented herein) to the consolidated financial statements appearing under Item 8 of the Company's 2018 annual report on Form 10-K, as to which the date is March 1, 2019.

We served as the Company's auditor from 1988 to 2018.

ORMAT TECHNOLOGIES, INC. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

	December 31,	
	2019	2018
	(Dollars in thousands)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 71,173	$ 98,802
Restricted cash and cash equivalents (primarily related to VIEs)	81,937	78,693
Receivables:		
Trade (primarily related to VIEs)	154,525	137,581
Other	22,048	19,393
Inventories	34,949	45,024
Costs and estimated earnings in excess of billings on uncompleted contracts	38,365	42,130
Prepaid expenses and other	12,667	51,441
Total current assets	415,664	473,064
Investment in unconsolidated companies	81,140	71,983
Deposits and other	38,284	18,209
Deferred income taxes	129,510	113,760
Property, plant and equipment, net ($1,880,547 and $1,859,228 related to VIEs, respectively)	1,971,415	1,959,578
Construction-in-process ($149,830 and $104,085 related to VIEs, respectively)	376,555	261,690
Operating leases right of use ($4,688 related to VIEs)	17,405	—
Finance leases right of use ($8,479 related to VIEs)	14,161	—
Deferred financing and lease costs, net	—	3,242
Intangible assets, net	186,220	199,874
Goodwill	20,140	19,950
Total assets	$ 3,250,494	$ 3,121,350
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable and accrued expenses	$ 141,857	$ 116,362
Short term revolving credit lines with banks (full recourse)	40,550	159,000
Commercial paper	50,000	—
Billings in excess of costs and estimated earnings on uncompleted contracts	2,755	18,402
Current portion of long-term debt:		
Limited and non-recourse (primarily related to VIEs):		
Senior secured notes	24,473	33,493
Other loans	34,458	29,687
Full recourse	76,572	5,000
Operating lease liabilities	2,743	—
Finance lease liabilities	3,068	—
Total current liabilities	376,476	361,944
Long-term debt, net of current portion:		
Limited and non-recourse (primarily related to VIEs):		
Senior secured notes (less deferred financing costs of $6,317 and $7,434, respectively)	339,336	375,337
Other loans (less deferred financing costs of $10,482 and $9,354, respectively)	317,395	320,242
Full recourse:		
Senior unsecured bonds (less deferred financing costs of $675 and $758, respectively)	286,453	303,575
Other loans (less deferred financing costs of $1,519 and $921, respectively)	68,747	41,579
Operating lease liabilities	14,008	—
Finance lease liabilities	11,209	—
Liability associated with sale of tax benefits	123,468	69,893
Deferred lease income	1,201	48,433
Deferred income taxes	97,126	61,323
Liability for unrecognized tax benefits	14,643	11,769
Liabilities for severance pay	18,751	17,994
Asset retirement obligation	50,183	39,475
Other long-term liabilities	6,838	16,087
Total liabilities	$ 1,725,834	$ 1,667,651
Commitments and contingencies (Note 22)		
Redeemable noncontrolling interest	9,250	8,603
Equity:		
The Company's stockholders' equity:		
Common stock, par value $0.001 per share; 200,000,000 shares authorized; 51,031,652 and 50,699,781 issued and outstanding as of December 31, 2019 and December 31, 2018, respectively	51	51
Additional paid-in capital	913,150	901,363
Retained earnings	487,873	422,222
Accumulated other comprehensive loss	(8,654)	(3,799)
Total stockholders' equity attributable to Company's stockholders	1,392,420	1,319,837
Noncontrolling interest	122,990	125,259
Total equity	1,515,410	1,445,096
Total liabilities, redeemable noncontrolling interest and equity	$ 3,250,494	$ 3,121,350

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

ORMAT TECHNOLOGIES, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME (LOSS)

	Year Ended December 31,		
	2019	2018	2017
	(Dollars in thousands, except per share data)		
Revenues:			
Electricity	$ 540,333	$ 509,879	$ 465,593
Product	191,009	201,743	224,483
Energy storage and management services	14,702	7,645	2,736
Total revenues	746,044	719,267	692,812
Cost of revenues:			
Electricity	312,835	298,255	266,840
Product	145,974	140,697	152,094
Energy storage and management services	17,912	9,880	5,426
Total cost of revenues	476,721	448,832	424,360
Gross profit	269,323	270,435	268,452
Operating expenses:			
Research and development expenses	4,647	4,183	3,157
Selling and marketing expenses	15,047	19,802	15,600
General and administrative expenses	55,833	47,750	42,881
Impairment charge	—	13,464	—
Write-off of unsuccessful exploration activities	—	126	1,796
Operating income	193,796	185,110	205,018
Other income (expense):			
Interest income	1,515	974	988
Interest expense, net	(80,384)	(70,924)	(54,142)
Derivatives and foreign currency transaction gains (losses)	624	(4,761)	2,654
Income attributable to sale of tax benefits	20,872	19,003	17,878
Other non-operating income (expense), net	880	7,779	(1,666)
Income from operations before income tax and equity in earnings (losses) of investees	137,303	137,181	170,730
Income tax (provision) benefit	(45,613)	(34,733)	(21,664)
Equity in earnings (losses) of investees, net	1,853	7,663	(1,957)
Net income	93,543	110,111	147,109
Net income attributable to noncontrolling interest	(5,448)	(12,145)	(14,695)
Net income attributable to the Company's stockholders	$ 88,095	$ 97,966	$ 132,414
Comprehensive income:			
Net income	93,543	110,111	147,109
Other comprehensive income (loss), net of related taxes:			
Change in foreign currency translation adjustments	(1,810)	(1,831)	3,440
Change in unrealized gains or losses in respect of the Company's share in derivatives instruments of unconsolidated investment	(3,417)	2,235	804
Change in respect of derivative instruments designated for cash flow hedge	75	81	135
Amortization of unrealized gains in respect of derivative instruments designated for cash flow hedge	(31)	(57)	(73)
Comprehensive income	88,360	110,539	151,415
Comprehensive income attributable to noncontrolling interest	(5,120)	(11,666)	(15,532)
Comprehensive income attributable to the Company's stockholders	$ 83,240	$ 98,873	$ 135,883
Earnings per share attributable to the Company's stockholders:			
Basic:			
Net income	$ 1.73	$ 1.93	$ 2.64
Diluted:			
Net income	$ 1.72	$ 1.92	$ 2.61
Weighted average number of shares used in computation of earnings per share attributable to the Company's stockholders:			
Basic	50,867	50,643	50,110
Diluted	51,227	50,969	50,769

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

ORMAT TECHNOLOGIES, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF EQUITY

	The Company's Stockholders' Equity							
	Common Stock		Additional Paid-in Capital	Retained Earnings (Accumulated Deficit)	Accumulated Other Comprehensive Income (Loss)	Total	Noncontrolling Interest	Total Equity
	Shares	Amount						
	(Dollars in thousands, except per share data)							
Balance at January 1, 2017	49,667	$ 50	$ 869,463	$ 215,352	$ (8,175)	$ 1,076,690	$ 91,582	$ 1,168,272
Stock-based compensation	—	—	8,760	—	—	8,760	—	8,760
Exercise of options by employees and directors	942	1	16,111	—	—	16,112	—	16,112
Cash paid to noncontrolling interest	—	—	—	—	—	—	(21,313)	(21,313)
Cash dividend declared, $0.41 per share	—	—	—	(20,511)	—	(20,511)	—	(20,511)
Buyout of Class B membership in ORTP	—	—	2,913	—	—	2,913	(6,964)	(4,051)
Buyout of Class B membership in OPC	—	—	(8,469)	—	—	(8,469)	6,537	(1,932)
Net income	—	—	—	132,414	—	132,414	13,643	146,057
Other comprehensive income (loss), net of related taxes:								
Foreign currency translation adjustments	—	—	—	—	2,603	2,603	837	3,440
Change in respect of derivative instruments designated for cash flow hedge	—	—	—	—	135	135	—	135
Change in unrealized gains or losses in respect of the Company's share in derivative instruments of unconsolidated investment	—	—	—	—	804	804	—	804
Amortization of unrealized gains in respect of derivative instruments designated for cash flow hedge (net of related tax of $46)	—	—	—	—	(73)	(73)	—	(73)
Balance at December 31, 2017	50,609	51	888,778	327,255	(4,706)	1,211,378	84,322	1,295,700
Cumulative effect of changes in accounting principles	—	—	—	23,835	—	23,835	—	23,835
Adjusted balance as of the beginning of the year	50,609	51	888,778	351,090	(4,706)	1,235,213	84,322	1,319,535
Stock-based compensation	—	—	10,218	—	—	10,218	—	10,218
Exercise of options by employees and directors	91	—	—	—	—	—	—	—
Cash paid to noncontrolling interest	—	—	—	—	—	—	(10,972)	(10,972)
Cash dividend declared, $0.53 per share	—	—	—	(26,834)	—	(26,834)	—	(26,834)
Increase in noncontrolling interest in Guadeloupe	—	—	—	—	—	—	5,339	5,339
Tax effect of partnership interest buyout	—	—	2,367	—	—	2,367	—	2,367
Increase in noncontrolling interest related to the Tungsten transaction	—	—	—	—	—	—	996	996
Purchase of U.S. Geothermal	—	—	—	—	—	—	34,898	34,898
Net income	—	—	—	97,966	—	97,966	11,155	109,121
Other comprehensive income (loss), net of related taxes:								
Foreign currency translation adjustments	—	—	—	—	(1,352)	(1,352)	(479)	(1,831)
Change in respect of derivative instruments designated for cash flow hedge (net of related tax of $24)	—	—	—	—	81	81	—	81
Change in unrealized gains or losses in respect of the Company's share in derivative instruments of unconsolidated investment (net of related tax of $0)	—	—	—	—	2,235	2,235	—	2,235
Amortization of unrealized gains in respect of derivative instruments designated for cash flow hedge (net of related tax of $18)	—	—	—	—	(57)	(57)	—	(57)
Balance at December 31, 2018	50,700	51	901,363	422,222	(3,799)	1,319,837	125,259	1,445,096
Cumulative effect of changes in accounting principles	—	—	—	(58)	—	(58)	—	(58)
Adjusted balance as of the beginning of the year	50,700	51	901,363	422,164	(3,799)	1,319,779	125,259	1,445,038
Stock-based compensation	—	—	9,358	—	—	9,358	—	9,358
Exercise of stock-based awards by employees and directors	332	—	2,429	—	—	2,429	—	2,429
Cash paid to noncontrolling interest	—	—	—	—	—	—	(8,329)	(8,329)
Cash dividend declared, $0.44 per share	—	—	—	(22,386)	—	(22,386)	—	(22,386)
Increase in noncontrolling interest in McGinness Hills 3	—	—	—	—	—	—	2,072	2,072
Net income	—	—	—	88,095	—	88,095	4,316	92,411
Other comprehensive income (loss), net of related taxes:								
Foreign currency translation adjustments	—	—	—	—	(1,482)	(1,482)	(328)	(1,810)
Change in respect of derivative instruments designated for cash flow hedge	—	—	—	—	75	75	—	75
Change in unrealized gains or losses in respect of the Company's share in derivative instruments of unconsolidated investment	—	—	—	—	(3,417)	(3,417)	—	(3,417)
Amortization of unrealized gains in respect of derivative instruments designated for cash flow hedge	—	—	—	—	(31)	(31)	—	(31)
Balance at December 31, 2019	51,032	51	913,150	487,873	(8,654)	1,392,420	122,990	1,515,410

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

ORMAT TECHNOLOGIES, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2019	2018	2017
	(Dollars in thousands)		
Cash flows from operating activities:			
Net income	$ 93,543	$ 110,111	$ 147,109
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	148,761	132,233	115,146
Accretion of asset retirement obligation	2,709	2,474	1,874
Stock-based compensation	9,358	10,218	8,760
Amortization of deferred lease income	(2,685)	(2,685)	(2,685)
Income attributable to sale of tax benefits, net of interest expense	(10,084)	(8,609)	(11,956)
Equity in losses (earnings) of investees, net	(1,853)	(7,663)	1,957
Mark-to-market of derivative instruments	(1,402)	2,032	(1,473)
Write-off of unsuccessful exploration activities	—	126	1,796
Impairment charge	—	13,464	—
Loss (gain) on severance pay fund asset	(1,016)	1,186	(1,746)
Deferred income tax provision	27,896	19,360	(41,147)
Liability for unrecognized tax benefits	2,874	2,879	3,270
Deferred lease revenues	(574)	(402)	(356)
Gain from insurance recoveries	—	(4,463)	—
Other	914	100	737
Changes in operating assets and liabilities, net of businesses acquired:			
Receivables	(15,133)	(29,928)	(24,040)
Costs and estimated earnings in excess of billings on uncompleted contracts	3,765	(1,185)	11,253
Inventories	5,500	(9,318)	(1,070)
Prepaid expenses and other	3,452	(11,172)	208
Change in operating lease right of use asset	8,167	—	—
Deposits and other	(22,525)	18	(2,570)
Accounts payable and accrued expenses	8,738	(56,724)	51,641
Billings in excess of costs and estimated earnings on uncompleted contracts	(15,647)	(1,839)	(11,389)
Liabilities for severance pay	757	(3,147)	2,541
Change in operating lease liabilities	(8,405)	—	—
Other liabilities, net	(617)	(11,244)	(2,285)
Net cash provided by operating activities	236,493	145,822	245,575
Cash flows from investing activities:			
Capital expenditures	(279,986)	(258,521)	(259,234)
Cash received from insurance recoveries	35,435	10,427	—
Investment in unconsolidated companies	(10,674)	(3,800)	(46,318)
Buyout of Class B membership in ORTP	—	—	(2,400)
Buyout of Class B membership in OPC	—	2,367	(1,932)
Cash paid for acquisition of controlling interest in a subsidiary, net of cash acquired	—	(95,093)	(35,300)
Intangible assets acquired	—	—	(868)
Decrease (increase) in severance pay fund asset, net of payments made to retired employees	687	2,186	526
Net cash used in investing activities	(254,538)	(342,434)	(345,526)
Cash flows from financing activities:			
Proceeds from sale of membership interests to noncontrolling interest, net of transaction costs	—	3,174	—
Proceeds from long-term loans, net of transaction costs	132,847	214,700	—
Proceeds from exercise of options by employees	2,429	—	16,111
Proceeds from the sale of limited liability company interest, net of transaction costs	58,289	32,175	—
Prepayment of long-term debt	(21,073)	—	(14,270)
Proceeds from issuance of commercial paper	50,000	—	—
Proceeds from revolving credit lines with banks	1,450,850	4,097,000	1,097,500
Repayment of revolving credit lines with banks	(1,569,300)	(3,989,500)	(1,046,000)
Cash received from noncontrolling interest	3,346	4,134	2,017
Cash paid for achievement of production threshold in GB	—	—	(8,032)
Repayments of long-term debt	(72,708)	(62,774)	(66,223)
Cash paid to noncontrolling interest	(9,730)	(13,106)	(21,313)
Payments under finance lease obligations	(3,164)	(2,551)	(1,871)
Deferred debt issuance costs	(5,165)	(5,287)	(5,290)
Cash dividends paid	(22,386)	(26,834)	(20,511)
Net cash provided by (used in) financing activities	(5,765)	251,131	(67,882)
Effect of exchange rate changes	(575)	(660)	—
Net change in cash and cash equivalents and restricted cash and cash equivalents	(24,385)	53,859	(167,833)
Restricted cash and cash equivalents acquired in a business combination	—	26,993	—
Cash and cash equivalents and restricted cash and cash equivalents at beginning of period	177,495	96,643	264,476
Cash and cash equivalents and restricted cash and cash equivalents at end of period	$ 153,110	$ 177,495	$ 96,643
Supplemental disclosure of cash flow information:			
Cash paid during the year for:			
Interest, net of interest capitalized	$ 61,628	$ 53,864	$ 40,484
Income taxes, net	$ 1,649	$ 18,028	$ 21,878
Supplemental non-cash investing and financing activities:			
Increase (decrease) in accounts payable related to purchases of property, plant and equipment	$ 9,423	$ (6,878)	$ 4,484
Right of use assets obtained in exchange for new lease liabilities	$ 11,626	$ 8,584	$ —
Increase in asset retirement cost and asset retirement obligation	$ 8,334	$ 881	$ 1,888

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

NOTE 1 — BUSINESS AND SIGNIFICANT ACCOUNTING POLICIES

Business

The Company is primarily engaged in the geothermal and recovered energy business, including the supply of equipment that is manufactured by the Company and the design and construction of power plants for projects owned by the Company or for third parties. The Company owns and operates geothermal and recovered energy-based power plants in various countries, including the United States, Kenya, Guatemala, Guadeloupe and Honduras. The Company's equipment manufacturing operations are located in Israel. Additionally, the Company provides energy storage, demand response and energy management related services as well as services relating to the engineering, procurement, construction, operation and maintenance of energy storage units.

Most of the Company's domestic power plant facilities are Qualifying Facilities under the PURPA. The Power Purchase Agreements ("PPAs") for certain of such facilities are dependent upon their maintaining Qualifying Facility status. Management believes that all of the facilities located in the United States were in compliance with Qualifying Facility status requirements as of December 31, 2019.

Cash dividends

During the years ended December 31, 2019, 2018 and 2017, the Company's Board of Directors (the "Board") declared, approved, and authorized the payment of cash dividends in the aggregate amount of $22.4 million ($0.44 per share), $26.8 million ($0.53 per share), and $20.5 million ($0.44 per share), respectively. Such dividends were paid in the years declared.

Rounding

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

Basis of presentation

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

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

Cash and cash equivalents

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

Restricted cash, cash equivalents, and marketable securities

Under the terms of certain long-term debt agreements, the Company is required to maintain certain debt service reserves, cash collateral and operating fund accounts that have been classified as restricted cash and cash equivalents. Funds that will be used to satisfy obligations due during the next 12 months are classified as current restricted cash and cash equivalents, with the remainder classified as non-current restricted cash and cash equivalents. Such amounts were invested primarily in money market accounts and commercial paper with a minimum investment grade of "A".

Reconciliation of cash and cash equivalents and restricted cash and cash equivalents

The following table provides a reconciliation of cash and cash equivalents and restricted cash and cash equivalents reported on the balance sheet that sum to the total of the same amounts shown on the statement of cash flows:

	December 31,		
	2019	2018	2017
	(Dollars in thousands)		
Cash and cash equivalents	$ 71,173	$ 98,802	$ 47,818
Restricted cash and cash equivalents	81,937	78,693	48,825
Total cash and cash equivalents and restricted cash and cash equivalents	$ 153,110	$ 177,495	$ 96,643

Concentration of credit risk

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

The Company places its temporary cash investments with high credit quality financial institutions located in the U.S. and in foreign countries. At December 31, 2019 and 2018, the Company had deposits totaling $12.9 million and $31.3 million, respectively, in ten United States financial institutions that were federally insured up to $250,000 per account. At December 31, 2019 and 2018, the Company's deposits in foreign countries of approximately $84.8 million and $93.9 million, respectively, were not insured.

At December 31, 2019 and 2018, accounts receivable related to operations in foreign countries amounted to approximately $118.8 million and $102.0 million, respectively. At December 31, 2019 and 2018, accounts receivable from the Company's major customers (see Note 19) amounted to approximately 58% and 56%, respectively, of the Company's accounts receivable.

The Company has historically been able to collect substantially all of its receivable balances. As of December 31, 2019, the amount overdue from KPLC in Kenya was $40.7 million of which $24.2 million was paid in January and February of 2020. These amounts represent an average of 70 days overdue, an increase of 10 days from September 30, 2019. In Honduras, the Company has been able to collect its current charges from Empresa Nacional de Energía Eléctrica ("ENEE") starting in May 2019, however, as of December 31, 2019, the amount overdue relating to the period from October 2018 to April 2019 was $20.1 million, none of which has been paid to date. Due to obligations of the Honduran government to support the Company, the Company believes it will be able to collect all past due amounts.

Additionally, Pacific Gas and Electric Corporation ("PG&E Corporation") and its subsidiary Pacific Gas and Electric Company ("PG&E"), which accounted for 1.5%, 1.9% and 2.0% of the Company's total revenues for the years ended December 31, 2019, 2018 and 2017, respectively, are facing extraordinary challenges relating to a series of catastrophic wildfires that occurred in Northern California in 2017 and 2018. As a result, on January 29, 2019, PG&E Corporation and its subsidiary, PG&E, voluntarily filed for reorganization under Chapter 11 of the U.S. Bankruptcy Code. The Company is closely monitoring its PG&E balance to ensure cash receipts are received on a timely basis each month. As of December 31, 2019, the outstanding balance relates to the current December 2019 invoices which were paid in January 2020.

Inventories

Inventories consist primarily of raw material parts and sub-assemblies for power units and are stated at the lower of cost or net realizable value, using the weighted-average cost method. Inventories are reduced by a provision for slow-moving and obsolete inventories. This provision was not material at December 31, 2019 and 2018.

Deposits and other

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

Property, plant and equipment, net

Property, plant and equipment are stated at cost. All costs associated with the acquisition, development and construction of power plants operated by the Company are capitalized. Major improvements are capitalized and repairs and maintenance (including major maintenance) costs are expensed. Power plants operated by the Company, which include geothermal wells and exploration and resource development costs, are depreciated using the straight-line method over their estimated useful lives, which range from 15 to 30 years. The other assets are depreciated using the straight-line method over the following estimated useful lives of the assets:

Buildings (in years)	25
Leasehold improvements (in years)	15 - 20
Machinery and equipment — manufacturing and drilling (in years)	10
Machinery and equipment — computers (in years)	3 - 5
Office equipment — furniture and fixtures (in years)	5 - 15
Office equipment — other (in years)	5 - 10
Vehicles (in years)	5 - 7

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

The Company capitalizes interest costs as part of constructing power plant facilities. Such capitalized interest is recorded as part of the asset to which it relates and is amortized over the asset's estimated useful life. Capitalized interest costs amounted to $3.3 million, $3.7 million, and $7.2 million for the years ended December 31, 2019, 2018 and 2017, respectively.

Exploration and development costs

The Company capitalizes costs incurred in connection with the exploration and development of geothermal resources once it acquires land rights to the potential geothermal resource. Prior to acquiring land rights, the Company makes an initial assessment that an economically feasible geothermal reservoir is probable on that land. The Company determines the economic feasibility of potential geothermal resources internally, with all available data and external assessments vetted through the exploration department and occasionally using outside service providers. Costs associated with the initial assessment are expensed and included in cost of electricity revenues in the consolidated statements of operations and comprehensive income (loss). Such costs were immaterial during the years ended December 31, 2019, 2018 and 2017. It normally takes two to three years from the time active exploration of a particular geothermal resource begins to the time a production well is in operation, assuming the resource is commercially viable. However, in certain sites the process may take longer due to permitting delays, transmission constraints or any other commercial milestones that are required to be reached in order to pursue the development process.

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

Following the acquisition of land rights to the potential geothermal resource, the Company conducts further studies and surveys, including water and soil analyses, among others, and augments its database with the results of these studies. The Company then initiates a suite of geophysical surveys to assess the resource and determine drilling locations. If the results of these activities support the initial assessment of the feasibility of the geothermal resource, the Company then proceeds to exploratory drilling and other related activities which may include drilling of temperature gradient holes, drilling of slim holes, building access roads to drilling locations, drilling full size production and/or injection wells and flow tests. If the slim hole supports a conclusion that the geothermal resource will support a commercially viable power plant, it may be converted to a full-size commercial well, used either for extraction or re-injection of geothermal fluids, or be used as an

observation well to monitor and define the geothermal resource. Costs associated with these activities and other directly attributable costs, including interest once physical exploration activities begin and permitting costs are capitalized and included in "construction-in-process". If the Company concludes that a geothermal resource will not support commercial operations, capitalized costs are expensed in the period such determination is made.

When deciding whether to continue holding lease rights and/or to pursue exploration activity, the Company diligently prioritizes prospective investments, taking into account resource and probability assessments in order to make informed decisions about whether a particular project will support commercial operation. As a result, write-off of unsuccessful activities for the years ended December 31, 2019, 2018 and 2017 was $0.0 million, $0.1 million, and $1.8 million, respectively. In 2017, the write-offs included exploration costs related to the Company's exploration activities in Oregon, after which the Company determined that the applicable sites would no longer support commercial operation.

Grants received from the U.S. DOE are offset against the related exploration and development costs. There were no such grants for the years ended December 31, 2019, 2018 and 2017.

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

Asset retirement obligation

The Company records the fair value of a legal liability for an asset retirement obligation in the period in which it is incurred. The Company's legal liabilities include plugging wells and post-closure costs of power producing sites. When a new liability for asset retirement obligations is recorded, the Company capitalizes the costs of the liability by increasing the carrying amount of the related long-lived asset. The liability is accreted to its present value each period, and the capitalized cost is depreciated over the useful life of the related asset. The Company periodically reassess the assumptions used to estimate the expected cash flows required to settle the asset retirement obligation, including changes in estimated probabilities, amounts, and timing of the settlement of the asset retirement obligation, as well as changes in the legal requirements of an obligation and revises the previously recorded asset retirement obligation accordingly. At retirement, the obligation is settled for its recorded amount at a gain or loss.

Deferred financing costs

Deferred financing costs are presented as a direct deduction from the carrying value of the associated debt liability or under deferred financing if associated with lines of credit. Such deferred costs are amortized over the term of the related obligation using the effective interest method or ratably, as applicable. Amortization of deferred financing costs is presented as interest expense in the consolidated statements of operations and comprehensive income (loss). Accumulated amortization related to deferred financing costs amounted to $19.5 million and $21.8 million at December 31, 2019 and 2018, respectively. Amortization expense for the years ended December 31, 2019, 2018 and 2017 amounted to $5.4 million, $4.6 million, and $5.7 million, respectively. During the years ended December 31, 2019, 2018 and 2017, amounts of $0.0 million, $0.0 million and $0.6 million, respectively, were written-off as a result of extinguishment of liabilities.

Goodwill

Goodwill represents the excess of the fair value of consideration transferred in the business combination transactions of Guadeloupe and USG over the fair value of tangible and intangible assets acquired, net of the fair value of liabilities assumed and the fair value of any noncontrolling interest in the acquisitions. Goodwill is not amortized but rather subject to a periodic impairment testing on an annual basis (on December 31 of each year) or if an event occurs or circumstances change that would more likely than not reduce the fair value of the reporting unit below its carrying amount. Additionally, an entity is permitted to first assess qualitative factors to determine whether a quantitative goodwill impairment test is necessary. Further testing is only required if the entity determines, based on the qualitative assessment, that it is more likely than not that a reporting unit's fair value is less than its carrying amount. Otherwise, no further impairment testing is required. An entity has the option to bypass the qualitative assessment for any reporting unit in any period and proceed directly to step one of the quantitative goodwill impairment test. This would not preclude the entity from performing the qualitative assessment in any subsequent period. The first step compares the fair value of the reporting unit to its carrying value, including goodwill. In January 2017, the FASB issued ASU 2017-04, Intangibles – Goodwill and Other (Topic 350), which

was adopted by the Company in 2018, under which step two of the goodwill impairment test was eliminated. Step two measured a goodwill impairment test by comparing the implied fair value of reporting unit's goodwill with the carrying amount of that goodwill. Under ASU 2017-04, Intangibles – Goodwill and Other, an entity should recognize an impairment charge for the amount by which the carrying amount of the reporting unit exceeds its fair value as calculated under step one described above. However, the loss recognized should not exceed the total amount of goodwill allocated to that reporting unit. For further information relating to goodwill see Note 9 - Intangible assets and goodwill to the consolidated financial statements.

Intangible assets

Intangible assets consist of allocated acquisition costs of PPAs, which are amortized using the straight-line method over the 13 to 29-year terms of the agreements (see Note 9) as well as acquisition cost allocation related to Viridity's storage activities that are amortized over a weighted average amortization period of 19 years. Intangible assets are tested for recoverability whenever events or changes in circumstances indicate that their carrying amount may not be recoverable. In case there is no such events or change in circumstances, there is no need to perform the impairment testing. The recoverability is tested by comparing the net carrying value of the intangible assets to the undiscounted net cash flows to be generated from the use and eventual disposition of these assets. If the carrying amount of a long-lived asset (or asset group) is not recoverable, the fair value of the asset (asset group) is measured and if the carrying amount exceeds the fair value, an impairment loss is recognized.

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

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

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

Recoverability of assets to be held and used is measured by a comparison of the carrying amount of an asset to the estimated future net undiscounted cash flows expected to be generated by the asset. The significant assumptions that the Company uses in estimating its undiscounted future cash flows include: (i) projected generating capacity of the complex or power plant and rates to be received under the respective PPAs and expected market rates thereafter and (ii) projected operating expenses of the relevant complex or power plant. Estimates of future cash flows used to test recoverability of a long-lived asset under development also include cash flows associated with all future expenditures necessary to develop the asset.

If the assets are considered to be impaired, the impairment to be recognized is measured by the amount by which the carrying amount of the assets exceeds their fair value. Assets to be disposed of are reported at the lower of the carrying amount or fair value less costs to sell. Management believes that no impairment exists for long-lived assets; however, estimates as to the recoverability of such assets may change based on revised circumstances. If actual cash flows differ significantly from the Company's current estimates, a material impairment charge may be required in the future.

Derivative instruments

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

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

Foreign currency translation

The U.S. dollar is the functional currency for all of the Company's consolidated operations and those of its equity affiliates except for the Guadeloupe power plant and the Company's operations in New Zealand. For those entities, all gains and losses from currency translations are included within the line item "Derivatives and foreign currency transaction gains (losses)" within the consolidated statements of operations and comprehensive income (loss). The Euro and New Zealand Dollar are the functional currencies of the Guadeloupe power plant and the Company's operations in New Zealand, respectively, and thus gains and losses from currency translation adjustments in those locations are included as currency translation adjustments in accumulated other comprehensive income in the consolidated statements of equity and in comprehensive income. The accumulated currency translation adjustments amounted to $1.5 million and $0.0 million as of December 31, 2019 and 2018, respectively.

Comprehensive income (loss) reporting

Comprehensive income (loss) includes net income or loss plus other comprehensive income (loss), which for the Company consists of changes in unrealized gains or losses in respect of the Company's share in derivatives instruments of an unconsolidated investment, foreign currency translation adjustments and changes in respect of derivative instruments designated as a cash flow hedge. The changes in foreign currency translation adjustments and gains or losses in respect of derivative instruments designated as a cash flow hedge during the years ended December 31, 2019, 2018 and 2017 were immaterial. The change in the Company's share in derivative instruments of unconsolidated investment is disclosed under Note 5 – Investment in unconsolidated companies to the consolidated financial statements.

Revenues and cost of revenues

Upon adoption of ASU 2014-09, Revenue from Contracts with Customers (Topic 606) on January 1, 2018, revenues from contracts with customers are recognized in connection with the transfer of goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. Specifically, the Company is required to apply each of the following steps: (1) identify the contract(s) with the customer; (2) identify the performance obligations in the contracts; (3) determine the transaction price; (4) allocate the transaction price to the performance obligations in the contract; and (5) recognize revenue when (or as) the entity satisfies a performance obligation.

Revenues are primarily related to: (i) sale of electricity from geothermal and recovered energy-based power plants owned and operated by the Company; (ii) geothermal and recovered energy-based power plant equipment engineering, sale, construction and installation, and operating services and (iii) energy storage, demand-response and energy management related services as well as services relating to the engineering, procurement, construction, operation and maintenance of energy storage units.

Electricity segment revenues: Revenues related to the sale of electricity from geothermal and recovered energy-based power plants and capacity payments are recorded based upon output delivered and capacity provided at rates specified under relevant contract terms. For PPAs agreed to, modified, or acquired in business combinations on or after July 1, 2003, the Company determines whether such PPAs contain a lease element requiring lease accounting. Revenue from such PPAs are

accounted for in electricity revenues. The lease element of the PPAs is also assessed in accordance with the revenue arrangements with multiple deliverables guidance, which requires that revenues be allocated to the separate earnings processes based on their relative fair value. PPAs with minimum lease rentals which vary over time are generally recognized on the straight-line basis over the term of the PPAs. PPAs with contingent rentals are recognized when earned. In the Electricity segment, revenues for all but five power plants are accounted as operating leases, and therefore equipment related to geothermal and recovered energy generation power plants as described in Note 8 is considered held for leasing. For power plants in the scope of ASC 606, the Company identified electricity as a separate performance obligation. Performance obligations identified were evaluated and determined to be satisfied over time and qualified for the invoicing practical expedient since the invoiced amounts reasonably represented the value to customers of performance obligations fulfilled to date. The transaction price is determined based on the price per actual mega-watt output or available capacity as agreed to in the respective PPA. Customers are generally billed on a monthly basis and payment is typically due within 30 to 60 days after the issuance of the invoice.

Product segment revenues: Revenues from engineering, operating services, and parts and product sales are recorded upon providing the service or delivery of the products and parts and when collectability is reasonably assured. Revenues from the supply and/or construction of geothermal and recovered energy-based power plant equipment and other equipment to third parties are recognized over time since control is transferred continuously to the Company's customers. The majority of the Company's contracts include a single performance obligation which is essentially the promise to transfer the individual goods or services that are not separately identifiable from other promises in the contracts and therefore deemed as not distinct. Performance obligations are satisfied over-time if the customer receives the benefits as we perform work, if the customer controls the asset as it is being constructed, or if the product being produced for the customer has no alternative use and the Company has a contractual right to payment. In the Company's Product segment, revenues are spread over a period of one to two years and are recognized over time based on the cost incurred to date in ratio to total estimated costs which represents the input method that best depicts the transfer of control over the performance obligation to the customer. Costs include direct material, labor, and indirect costs. Provisions for estimated losses on uncompleted contracts are made in the period in which such losses are determined.

In contracts for which the Company determines that control is not transferred continuously to the customer, the Company recognizes revenues at the point in time when the customer obtains control of the asset. Revenues for such contracts are recorded upon delivery and acceptance by the customer. This generally is the case for the sale of spare parts, generators or similar products.

Accounting for product contracts that are satisfied over time includes use of several estimates such as variable consideration related to bonuses and penalties and total estimated cost for completing the contract. The estimated amount of variable consideration will be included in the transaction price only to the extent that it is probable that a significant reversal in the amount of cumulative revenue recognized will not occur when the uncertainty associated with the variable consideration is subsequently resolved. These estimates are based on historical experience, anticipated performance and the Company's best judgment at the time.

The nature of the Company's product contracts give rise to several modifications or change requests by its customers. Substantially all of the modifications are treated as cumulative catch-ups to revenues since the additional goods are not distinct from those already provided. The Company includes the additional revenues related to the modifications in its transaction price when both parties to the contract approved the modification. As a significant change in one or more of these estimates could affect the profitability of the Company's contracts, the Company reviews and updates its contract-related estimates regularly. If at any time the estimate of contract profitability indicates an anticipated loss on the contract, the Company recognizes the total loss in the period in which it is identified.

Energy Storage and Management Services segment revenues: Battery energy storage systems as a service, demand-response and energy management related services revenues are recorded based on energy management of load curtailment capacity delivered or service provided at rates specified under the relevant contract terms. The Company determined that such revenues are in the scope of ASC 606 and identified energy management services as a separate performance obligation. Performance obligations are satisfied once the Company provides verification to the electric power grid operator or utility of its ability to meet the committed capacity, the power curtailment requirements or the ancillary services and thus entitled to cash proceeds. Such verification may be provided by the Company bi-weekly, monthly or under any other frequency as set by the related program and are typically followed by a payment shortly after. Performance obligations identified were evaluated and determined to be satisfied over time and qualified for the invoicing practical expedient since the amounts

included in the verification document reasonably represent the value of performance obligations fulfilled to date. The transaction price is determined based on mechanisms specified in the contract with the customer.

The Company's accounting policy for revenues included under the 2017 comparative period were accounted under the previous accounting standard as follows:

Revenues related to the sale of electricity from geothermal and recovered energy-based power plants and capacity payments are recorded based upon output delivered and capacity provided at rates specified under relevant contract terms. For PPAs agreed to, modified, or acquired in business combinations on or after July 1, 2003, the Company determines whether such PPAs contain a lease element requiring lease accounting. Revenue from such PPAs are accounted for in electricity revenues. The lease element of the PPAs is also assessed in accordance with the revenue arrangements with multiple deliverables guidance, which requires that revenues be allocated to the separate earnings processes based on their relative fair value. PPAs with minimum lease rentals which vary over time are generally recognized on the straight-line basis over the term of the PPAs. PPAs with contingent rentals are recognized when earned. In the electricity segment, revenues for all but five power plants are accounted as operating leases, and therefore equipment related to geothermal and recovered energy generation power plants as described in Note 8 is considered held for leasing.

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

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

Contract assets related to the Company's Product segment reflect revenues recognized and performance obligations satisfied in advance of customer billing. Contract liabilities related to the Company's Product segment reflect payments received in advance of the satisfaction of performance under the contract. The Company receives payments from customers based on the terms established in the contracts. Total contract assets and contract liabilities as of December 31, 2019 and 2018 are as follows.

	December 31, 2019	December 31, 2018
	(Dollars in thousands)	
Contract assets (*)	$ 38,365	$ 42,130
Contract liabilities (*)	(2,755)	(18,402)
Contract assets, net	$ 35,610	$ 23,728

(*) Contract assets and contract liabilities are presented as "Costs and estimated earnings in excess of billings on uncompleted contracts" and "Billings in excess of costs and estimated earnings on uncompleted contracts", respectively, on the consolidated balance sheets. The contract liabilities balance at the beginning of the year was fully recognized as product revenues during the years ended December 31, 2019 and 2018 as a result of performance obligations satisfied.

The following table presents the significant changes in the contract assets and contract liabilities for the years ended December 31, 2019 and 2018:

	Years Ended December 31,			
	2019		2018	
	Contract assets	Contract liabilities	Contract assets	Contract liabilities
	(Dollars in thousands)			
Recognition of contract liabilities as revenue as a result of performance obligations satisfied	$ —	$ 12,675	$ —	$ 33,349
Cash received in advance for which revenues have not yet recognized, net of expenditures made	—	(3,323)	—	(38,162)
Reduction of contract assets as a result of rights to consideration becoming unconditional	(130,918)	—	(128,659)	—
Contract assets recognized, net of recognized receivables	133,448	—	136,496	—
Net change in contract assets and contract liabilities	$ 2,530	$ 9,352	$ 7,837	$ (4,813)

The timing of revenue recognition, billings and cash collections results in accounts receivable, contract assets and contract liabilities on the consolidated balance sheet. In the Company's Products segment, amounts are billed as work progresses in accordance with agreed-upon contractual terms, or upon achievement of contractual milestones. Generally, billing occurs subsequent to the recognition of revenue, resulting in contract assets. However, the Company sometimes receives advances or deposits from its customers before revenue can be recognized, resulting in contract liabilities. These assets and liabilities are reported on the consolidated balance sheet on a contract-by-contract basis at the end of each reporting period. The timing of billing its customers and receiving advance payments vary from contract to contract. The majority of payments are received no later than the completion of the project and satisfaction of the Company's performance obligation.

On December 31, 2019, the Company had approximately $139.3 million of remaining performance obligations not yet satisfied or partly satisfied related to its Product segment. The Company expects to recognize approximately 100% of this amount as Product revenues during the next 24 months.

The following schedule reconciles revenues accounted under lease accounting, and ASC 606, Revenues from Contracts with Customers, to total consolidated revenues for the years ended December 31, 2019 and 2018:

	Year Ended December 31,	
	2019	2018
	(Dollars in thousands)	
Electricity Revenues accounted under lease accounting	$ 479,059	$ 481,619
Electricity, Product and Energy Storage and Management Services revenues accounted under ASC 606	266,985	237,648
Total consolidated revenues	$ 746,044	$ 719,267

Disaggregated revenues from contracts with customers for the years ended December 31, 2019 and 2018 are disclosed under Note 19 - Business Segments, to the consolidated financial statements.

Termination fee

Fees to terminate PPAs are recognized in the period incurred as selling and marketing expenses. During 2018, the Company signed a termination agreement with NV Energy, Inc. for the Galena 2 PPA under which it agreed to pay a termination fee of approximately $5 million which was recorded under Selling and marketing expenses in 2018. In 2019 and 2017, no termination fees were incurred.

Warranty on products sold

The Company generally provides a one to two years warranty against defects in workmanship and materials related to the sale of products for electricity generation. The Company considers the warranty to be an assurance type warranty since the warranty provides the customer the assurance that the product complies with agreed-upon specifications. Estimated future warranty obligations are included in operating expenses in the period in which the related revenue is recognized. Such charges are immaterial for the years ended December 31, 2019, 2018 and 2017.

Research and development

Research and development costs incurred by the Company for the development of existing and new geothermal and recovered energy power plants as well as storage related technologies are expensed as incurred. Grants received from the DOE are offset against the related research and development expenses. There were no such grants for the years ended December 31, 2019, 2018 and 2017.

Stock-based compensation

The Company accounts for stock-based compensation using the fair value method whereby compensation cost is measured at the grant date, based on the calculated fair value of the award, and is recognized as an expense over the requisite employee service period (generally the vesting period of the grant). The Company uses the Exercise Multiple-Based Lattice SAR-Pricing Model to value the stock-based compensation awards to reflect accumulated historic data retained of behavioral parameters.

Tax monetization Transactions

The Company has three tax monetization transactions, Opal Geo, Tungsten and McGinness Hills 3 as further described under Note 13 – tax monetization transactions to the consolidated financial statements. The OPC and ORTP tax monetization transactions terminated during 2017 upon the Company's partners reaching their target after-tax yield on their investment, as further described in Note 13. The purpose of these transactions is to form tax partnerships, whereby investors provide cash in exchange for equity interests that provide the holder a right to the majority of tax benefits associated with a renewable energy project. The Company accounts for a portion of the proceeds from the transaction as debt under ASC 470. Given that a portion of these transactions is structured as a purchase of an equity interest the Company also classifies a portion as noncontrolling interest consistent with guidance in ASC 810. The portion recorded to noncontrolling interest is initially measured as the fair value of the discounted tax attributes and cash distributions which represents the partner's residual economic interest. The residual proceeds are recognized as the initial carrying value of the debt which is classified as a liability associated with sale tax benefits. The Company applies the effective interest rate method to the liability associated with the tax monetization transaction component as described by ASC 835 and CON 7. The tax benefits and cash distributions realized by the partner each period are treated as the debt servicing amounts, with the tax benefit amounts giving rise to income attributable to the sale of tax benefits. The deferred transaction costs have been capitalized and amortized using the effective interest method.

Income taxes

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

Earnings per share

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

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

	Year Ended December 31,		
	2019	2018	2017
	(In thousands)		
Weighted average number of shares used in computation of basic earnings per share	50,867	50,643	50,110
Add:			
Additional shares from the assumed exercise of employee stock options	360	326	659
Weighted average number of shares used in computation of diluted earnings per share	51,227	50,969	50,769

The number of stock-based awards that could potentially dilute future earnings per share and were not included in the computation of diluted earnings per share because to do so would have been anti-dilutive was 360.5 thousand, 176.4 thousand, and 42.9 thousand, respectively, for the years ended December 31, 2019, 2018 and 2017.

Use of estimates in preparation of financial statements

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

Redeemable noncontrolling interest

Changes in the carrying amount of the Company's Redeemable noncontrolling interest were as follows:

	2019	2018
	(Dollars in thousands)	
Redeemable noncontrolling interest as of January 1,	$ 8,603	$ 6,416
Redeemable noncontrolling interest in results of operation of a consolidated subsidiary	1,132	990
Cash paid to noncontrolling interest	(252)	—
Increase in share of redeemable noncontrolling interest	—	1,528
Currency translation adjustments	(233)	(331)
Redeemable noncontrolling interest as of December 31,	$ 9,250	$ 8,603

Puna Power Plant

On May 3, 2018, the Kilauea volcano located in close proximity to the Company's Puna 38 MW geothermal power plant in the Puna district of Hawaii's Big Island erupted following a significant increase in seismic activity in the area. Before it stopped flowing, the lava covered the wellheads of three geothermal wells, monitoring wells and the substation of the Puna complex and an adjacent warehouse that stored a drilling rig that was also consumed by the lava. The insurance policy coverage for property and business interruption is provided by a consortium of insurers. All the insurers accepted and started paying for the costs to rebuild the destroyed substation, and during 2019, the Company received an additional $1.1 million of such proceeds. However, only some of the insurers accepted that the business interruption coverage started in May 2018 and during 2019, the Company received and recorded an additional $9.3 million of such proceeds, which were included under cost of revenues in the consolidated statements of operations and comprehensive income for the year ended December 31, 2019. The Company has filed a lawsuit against the insurers that do not accept its claim.

As of February 2020, the reconstruction efforts at Puna continue. Permits that are required for the construction and operation of the substation are delayed and currently expected during the first half of 2020. HELCO continue with their efforts to complete the upgrade of the transmission network. On the field side, the Company completed the drilling of one production well that was blocked immediately after flow test of the well. The Company continues its field recovery work, which includes redrilling of existing wells, cleanouts and drilling of new wells and expects initial power generation for testing during the second quarter of 2020. Commercial operation of the full generating capacity of the Puna power plant is expected in the third quarter of 2020 assuming all permits are received, transmission network upgrade is complete and field recovery is successfully achieved.

The Company continues to assess the accounting implications of this event on the assets and liabilities on its balance sheet and whether an impairment will be required. Any significant damage to the geothermal resource or continued shut-down following the lava event at the Puna facilities could have an adverse impact on the power plant's electricity generation and availability, which in turn could have a material adverse impact on the Company's business and results of operations.

New Accounting Pronouncements

***New accounting pronouncements effective in the year ended* December 31, 2019**

Leases

In February 2016, the FASB issued ASU 2016-02, Leases (Topic 842). This new standard introduced a number of changes and simplified previous guidance, primarily the recognition of lease assets and lease liabilities by lessees for those leases classified as operating leases. The new standard retained the distinction between finance leases and operating leases and the classification criteria between the two types remains substantially similar. Also, lessor accounting remained largely unchanged from previous guidance. However, key aspects of the new standard were aligned with the revenue recognition guidance in Topic 606. Additionally, the new standard defined a lease as a contract, or part of a contract, that conveys the right to control the use of an identified asset for a period of time in exchange for consideration. Control over the use of the identified asset means that the customer has both (a) the right to obtain substantially all of the economic benefits from the use of the asset and (b) the right to direct the use of the asset. The Company adopted this new standard as of January 1, 2019 using the modified retrospective approach and accordingly recognized a cumulative-effect adjustment to the opening balance of retained earnings, which was an immaterial amount, with no restatement of comparative information.

The Company is a lessee in operating lease transactions primarily consisting of land leases for its exploration and development activities as further described under Exploration and development costs above and the Puna power plant transaction as further described under Note 12 to the consolidated financial statements. Additionally, the Company is a lessee in finance lease transactions primarily consisting of fleet vehicles and office rentals. As further described above under Revenues and cost of revenues, the Company acts as a lessor in PPAs that are accounted under ASC 842, Leases.

In accordance with the new standard, for agreements in which the Company is the lessee, the Company applies a unified accounting model by which it recognizes a right-of-use asset ("ROU") and a lease liability at the commencement date of the lease contract for all the leases in which the Company has a right to control identified assets for a specified period of time. The classification of the lease as a finance lease or an operating lease determines the subsequent accounting for the lease arrangement.

Upon the adoption of the new standard the Company, both as a lessee and as a lessor, chose to apply the following permitted practical expedients:

1. Not reassess whether any existing contracts are or contain a lease;

2. Not reassess the classification of leases that commenced before the effective date (for example, all existing leases that were classified as operating leases in accordance with Topic 840 will continue to be classified as operating leases, and all existing leases that were classified as capital leases in accordance with Topic 840 will continue to be classified as finance leases);

3. Exclude initial direct costs from measurement of the ROU asset at the date of initial application;

4. Applying the practical expedient (for a lessor) to not separate non-lease components accounted for under Topic 606 from lease components and, instead, to account for each separate lease component and the non-lease components associated with that lease component as a single component. If the non-lease components are the predominant components, the Company will account for the combined component as a single performance obligation entirely in accordance with Topic 606. Otherwise, the combined component will be accounted as an operating lease entirely in accordance with the new standard.

5. Applying the practical expedient (for a lessee) regarding the recognition and measurement of short-term leases, for leases for a period of up to 12 months from the commencement date. Instead, the Company will continue to recognize the lease payments for those leases in profit or loss on a straight-line basis over the lease term.

Since the Company elected to apply the practical expedients above, it applied the new standard to all contracts entered into before January 1, 2019 and identified as leases in accordance with Topic 840.

The new significant accounting policies regarding leases that were applied as from January 1, 2019 following the application of the new standard are as follows:

1. Determining whether an arrangement contains a lease

On the inception date of the lease, the Company determines whether the arrangement is a lease or contains a lease, while examining if it conveys the right to control the use of an identified asset for a period of time in exchange for consideration.

2. The Company as a lessee

a. Lease classification:

At the commencement date, a lease is a finance lease if it meets any one of the criteria below; otherwise the lease is an operating lease:

- The lease transfers ownership of the underlying asset to the lessee by the end of the lease term.
- The lease grants the lessee an option to purchase the underlying asset that the lessee is reasonably certain to exercise.
- The lease term is for the major part of the remaining economic life of the underlying asset.
- The present value of the sum of the lease payments and any residual value guaranteed by the lessee that is not already reflected in the lease payments equals or exceeds substantially all of the fair value of the underlying asset.
- The underlying asset is of such a specialized nature that it is expected to have no alternative use to the lessor at the end of lease term.

b. Leased assets and lease liabilities - initial recognition

Upon initial recognition, the Company recognizes a liability at the present value of the lease payments to be made over the lease term, and concurrently recognizes a ROU asset at the same amount of the liability, adjusted for any prepaid or accrued lease payments, plus initial direct costs incurred in respect of the lease. Since the interest rate implicit in the lease is

not readily determinable, the incremental borrowing rate of the Company is used. The subsequent measurement depends of whether the lease is classified as a finance lease or an operating lease.

c. The lease term

The lease term is the non-cancellable period of the lease plus periods covered by an extension or termination option if it is reasonably certain that the Company will exercise the option.

d. Subsequent measurement of operating leases

After lease commencement, the Company measures the lease liability at the present value of the remaining lease payments using the discount rate determined at lease commencement (as long as the discount rate has not been updated as a result of a reassessment event).

The Company subsequently measures the ROU asset at the present value of the remaining lease payments, adjusted for the remaining balance of any lease incentives received, any cumulative prepaid or accrued rent if the lease payments are uneven throughout the lease term and any unamortized initial direct costs.

Further, the Company will recognize lease expense on a straight-line basis over the lease term.

e. Subsequent measurement of finance leases

After lease commencement, the Company measures the lease liability by increasing the carrying amount to reflect interest on the lease liability and reducing the carrying amount to reflect the lease payments made during the period. The Company shall determine the interest on the lease liability in each period during the lease term as the amount that produces a constant periodic discount rate on the remaining balance of the liability, taking into consideration the reassessment requirements.

After lease commencement, the Company measures the ROU assets at cost less any accumulated amortization and any accumulated impairment losses, taking into consideration the reassessment requirements. The Company amortizes the ROU asset on a straight-line basis, unless another systematic basis better represents the pattern in which the Company expects to consume the ROU asset's future economic benefits. The ROU asset is amortized over the shorter of the lease term or the useful life of the ROU asset as follows:

	(in years)
Land	1 - 35
Vehicles	5
Building	15

The total periodic expense (the sum of interest and amortization expense) of a finance lease is typically higher in the early periods and lower in the later periods.

f. Variable lease payments:

Variable lease payments that depend on an index or a rate

On the commencement date, the lease payments shall include variable lease payments that depend on an index or a rate (such as the Consumer Price Index or a market interest rate), initially measured using the index or rate at the commencement date.

The Company does not remeasure the lease liability for changes in future lease payments arising from changes in an index or rate unless the lease liability is remeasured for another reason. Therefore, after initial recognition, such variable lease payments are recognized in profit or loss as they are incurred.

Other variable lease payments:

Variable payments that depends on performance or use of the underlying asset are not included in the lease payments. Such variable payments are recognized in profit or loss in the period in which the event or condition that triggers the payment occurs.

3. The Company as a lessor

At lease commencement, the Company as a lessor classifies leases as either finance or operating leases. Finance leases are further classified as a sales-type lease or as a direct financing lease.

Under an operating lease, the Company recognizes the lease payment as income over the lease term, generally on a straight-line basis or as earned.

4. Impact of the new standard

a) The effects of the initial application of the new standard on the Company's consolidated balance sheet as of January 1, 2019 are as follows:

	According to the previous accounting policy	The change	As presented according to Topic 842
	(Dollars in thousands)		
As of January 1, 2019:			
Prepaid expenses and other	$ 51,441	$ (35,385)	$ 16,056
Deferred financing and lease costs, net	3,242	(1,659)	1,583
Property, plant and equipment, net	1,959,578	(12,855)	1,946,723
Operating leases right of use	—	62,244	62,244
Finance leases right of use	—	13,476	13,476
Accounts payable and accrued expenses	116,362	(2,860)	113,502
Current maturity of operating lease liabilities	—	7,532	7,532
Current maturity of finance lease liabilities	—	2,841	2,841
Other long-term liabilities	16,087	(9,970)	6,117
Long term portion of operating lease liabilities	—	17,668	17,668
Long term portion of finance lease liabilities	—	10,668	10,668
Retained earnings	422,222	(58)	422,164

The operating leases right of use is higher than the related lease liabilities as a result of prepayments of leases, including the Puna lease and deferred financing lease costs.

b) A weighted-average nominal incremental interest rate of 5% and 7% was used to discount future lease payments in the calculation of the lease liabilities in respect of operating leases and in respect of finance leases, respectively.

Derivatives and Hedging

In August 2017, the FASB issued ASU 2017-12, Targeted Improvements to Accounting for Hedging Activities. The amendments in this update better align an entity’s risk management activities and financial reporting for hedging relationships through changes to both the designation and measurement guidance for qualifying hedging relationships and the presentation of hedge results. To meet that objective, the amendments expand and refine hedge accounting for both nonfinancial and financial risk components and align the recognition and presentation of the effects of the hedging instrument and the hedged item in the financial statements. The amendments in this update are effective for fiscal years

beginning after December 15, 2018, and interim periods within those fiscal years. The adoption of this guidance did not have an impact on the Company's consolidated financial statements.

Reclassification of Certain Tax Effects from Accumulated Other Comprehensive Income

In February 2018, the FASB issued ASU 2018-02, Income Statement - Reporting Comprehensive Income (Topic 220). The amendments in this update allow a reclassification from accumulated other comprehensive income to retained earnings for stranded tax effects resulting from the Tax Cuts and Jobs Act of 2017 (the "Tax Act"). The guidance is effective for the fiscal years beginning after December 15, 2018, and interim periods within those fiscal years. The adoption of this guidance did not have an impact on the Company's consolidated financial statements.

New accounting pronouncements effective in future periods

Financial Instruments - Credit Losses

In June 2016, the FASB issued ASU 2016-13, *Financial Instruments-Credit Losses (Topic* 326*)*-Measurement of Credit Losses on Financial Instruments. This guidance replaces the current incurred loss impairment methodology. Under the new guidance, on initial recognition and at each reporting period, an entity is required to recognize an allowance that reflects its current estimate of credit losses expected to be incurred over the life of the financial instrument based on historical experience, current conditions and reasonable and supportable forecasts. In November 2018, the FASB issued ASU 2018-19, Codification Improvements to Topic 326, Financial Instruments - Credit Losses. ASU 2018-19 clarifies that receivables from operating leases are accounted for using the lease guidance and not as financial instruments. The guidance is effective beginning on January 1, 2020, including interim periods within that year and requires a modified retrospective transition approach through a cumulative-effect adjustment to retained earnings as of the beginning of the period of adoption. Under the modified retrospective method of adoption, prior year reported results are not restated. The Company has analyzed the impact of its financial instruments that are within the scope of this guidance, primarily receivables and costs and estimated earnings in excess of billings on uncompleted contracts, and believes that the cumulative adjustment to retained earnings will have an immaterial effect on its consolidated financial statements.

Accounting for Income Taxes

In December 2019, the FASB issued ASU 2019-12, Income Taxes (Topic 740): Simplifying the Accounting for Income Taxes. ASU 2019- 12 is intended to simplify the accounting for income taxes by removing certain exceptions to the general principles in ASC 740. The standard is effective for annual periods beginning after December 15, 2020 and interim periods within. Early adoption permitted. The Company has not early adopted ASU 2019-12 as of December 31, 2019. The Company does not anticipate ASU 2019-12 will have a material impact on its consolidated financial statements.

NOTE 2 —BUSINESS ACQUISITIONS AND OTHERS

Ijen transaction

On July 2, 2019, the Company agreed to acquire 49% in the Ijen geothermal project company from a subsidiary of Medco Power ("Medco"), which is party to a Power Purchase Agreement and holds a geothermal license to develop the Ijen project in East Java in Indonesia for a total consideration of approximately $2.7 million. As part of the transaction, the Company committed to make additional funding for the exploration and development of the project, subject to specific conditions. During the fourth quarter of 2019, the Company made an additional cash investment of $7.4 million. Medco retains 51% ownership in the project company and the Company and Medco will develop the project jointly. The Company accounted for its investment in the Ijen geothermal project company under the equity method prescribed by ASC 323 - Investments - Equity Method and Joint Ventures.

USG transaction

On April 24, 2018, the Company completed the acquisition of USG. The total cash consideration (exclusive of transaction expenses) was approximately $110 million, comprised of approximately $106 million funded from available cash of Ormat Nevada Inc. (to acquire the outstanding shares of common stock of USG) and approximately $4 million funded from available cash of USG (to cash-settle outstanding in-the-money options for common stock of USG). As a result of the acquisition, USG became an indirect wholly owned subsidiary of Ormat, and Ormat indirectly acquired, among other things, interests held by USG and its subsidiaries in:

- three operating power plants at Neal Hot Springs, Oregon; San Emidio, Nevada; and Raft River, Idaho with a total net generating capacity of approximately 38 MW; and
- development assets which include a project at the Geysers, California; a second phase project at San Emidio, Nevada; a greenfield project in Crescent Valley, Nevada; and the El Ceibillo project located near Guatemala City, Guatemala.

As a result of the acquisition, the Company expanded its overall generation capacity and improved the profitability of the purchased assets through cost reduction and synergies. The Company accounted for the transaction in accordance with Accounting Standard Codification ASC 805, Business Combinations and following the transaction, the Company consolidates USG, in accordance with Accounting Standard Codification ASC 810, Consolidation.

The following table summarizes the purchase price allocation to the fair value of the assets acquired and liabilities assumed (in millions):

Cash and cash equivalents and restricted cash	$	37.9
Property, plant and equipment and construction-in-process		77.3
Intangible assets [(1)]		127.0
Goodwill [(2)]		12.7
Deferred taxes		1.7
Total assets acquired	$	256.6
Other working capital	$	(8.2)
Long-term term debt		(98.3)
Asset retirement obligation		(9.0)
Noncontrolling interest		(34.9)
Total liabilities assumed	$	(150.4)
Total assets acquired, and liabilities assumed, net	$	106.2

(1) Intangible assets are primarily related to long-term electricity power purchase agreements and depreciated over an average of 19 years.

(2) Goodwill is primarily related to the expected synergies in operations as a result of the purchase transaction. The goodwill is allocated to the Electricity segment and not deductible for tax purposes.

The fair value of the noncontrolling interest of $34.9 million reflects the 40% minority interests in the Neal Hot Springs project that was evaluated using the income approach. The fair value of the noncontrolling interest was based on the following significant inputs: (i) forecasted cash flows assumed to be generated in correspondence with the remaining life of the related power purchase agreement which is approximately 20 years; (ii) revenues were estimated in accordance with the price and generation capacity of the related power purchase agreement; (iii) assumed terminal value based on the realizable value of the project at the end of the power purchase agreement term; and (iv) assumed discount rate of approximately 9%.

Total Electricity revenues and operating profit related to the three USG power plants of approximately $21.4 million and $2.5 million, respectively, for the period started at the acquisition date to December 31, 2018 were included in the Company's consolidated statements of operations and comprehensive income for the year ended December 31, 2018. The following unaudited pro forma summary presents consolidated information of the Company as if the business combination had occurred on January 1, 2017:

	Pro forma for the year ended December 31, 2018	Pro forma for the year ended December 31, 2017
	(Dollars in thousands)	
Electricity revenues	$ 521,175	$ 497,650
Total revenues	730,563	724,869
Income from continuing operations before income taxes and equity in losses of investees	134,142	169,546

Viridity transaction

On March 15, 2017, the Company completed the acquisition of substantially all of the business and assets of Viridity Energy, Inc., a privately held Philadelphia-based company formerly engaged in the provision of demand response, energy management and energy storage services. At closing, Viridity Energy Solutions Inc. ("Viridity"), a wholly owned subsidiary of the Company, paid initial consideration of $35.3 million. Additional contingent consideration with an estimated fair value of $12.4 million was set upon the achievement of certain performance milestones to be measured at the end of fiscal years 2017 and 2020. The first performance milestone measured at the end of 2017 was not achieved and as of December 31, 2018 the Company estimated that the second milestone to be measured at the end of fiscal year 2020 will not be achieved. As a result, the Company reversed the related contingent considerations in the amount of $0.6 million and $10.3 million in 2017 and 2018, respectively, both were recorded under general and administrative expenses in the consolidated statement of operations and comprehensive income (loss).

The Company accounted for the transaction in accordance with Accounting Standard Codification 805, Business Combinations, and consequently recorded intangible assets of $34.7 million primarily relating to Viridity's storage activities with a weighted-average amortization period of 19 years, approximately $0.4 million of working capital and fixed assets and $13.5 million of goodwill. Following the transaction, the Company consolidated Viridity in accordance with Accounting Standard Codification 810, Consolidation. The acquisition enabled the Company to enter the growing energy storage and demand response markets and expand its market presence.

In 2018, the Company recorded an impairment charge for the full amount of goodwill associated with its storage and energy management services in its consolidated statements of operations and comprehensive income (loss). Further information related to this impairment charge is disclosed in Note 9 – "Intangible assets and goodwill" to the consolidated financial statements.

NOTE 3 — INVENTORIES

Inventories consist of the following:

	December 31,	
	2019	2018
	(Dollars in thousands)	
Raw materials and purchased parts for assembly	$ 21,942	$ 26,914
Self-manufactured assembly parts and finished products	13,007	18,110
Total	$ 34,949	$ 45,024

NOTE 4 — COST AND ESTIMATED EARNINGS ON UNCOMPLETED CONTRACTS

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

	December 31,	
	2019	2018
	(Dollars in thousands)	
Costs and estimated earnings incurred on uncompleted contracts	$ 196,550	$ 278,797
Less billings to date	(160,940)	(255,069)
Total	$ 35,610	$ 23,728

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

	December 31,	
	2019	2018
	(Dollars in thousands)	
Costs and estimated earnings in excess of billings on uncompleted contracts	$ 38,365	$ 42,130
Billings in excess of costs and estimated earnings on uncompleted contracts	(2,755)	(18,402)
Total	$ 35,610	$ 23,728

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

NOTE 5 — Investment in unconsolidated companies

Investment in unconsolidated companies mainly consists of the following:

	December 31,	
	2019	2018
	(Dollars in thousands)	
Sarulla	$ 70,589	$ 71,983
Ijen	10,551	—
Total investment in unconsolidated companies	$ 81,140	$ 71,983

The Sarulla Complex

The Company holds a 12.75% equity interest in a consortium that developed the 330 MW Sarulla geothermal power plant project in Tapanuli Utara, North Sumatra, Indonesia. The Sarulla project is comprised of three separately constructed 110 MW units, the most recent of which, NIL 2, was completed in April 2018. The Sarulla project is owned and operated by the consortium members under the framework of a joint operating contract and energy sales contract that were both executed on April 4, 2013. Under the joint operating contract, PT Pertamina Geothermal Energy, the concession holder for the project, provided the consortium with the right to use the geothermal field, and under the energy sales contract, PT PLN, the state electric utility, is the off-taker at the Sarulla complex for a period of 30 years.

During the years ended December 31, 2019 and 2018, the Company made additional cash equity investments in the Sarulla complex of approximately $0.0 million and $3.8 million, respectively, for a total of $62.0 million since inception.

The Sarulla consortium entered into interest rate swap agreements with various international banks, effective as of June 4, 2014, and accounted for the interest rate swap as a cash flow hedge upon which changes in the fair value of the hedging instrument, relative to the effective portion, are recorded in other comprehensive income. The Company's share of such gains (losses) recorded in other comprehensive income (loss) are as follows:

	Year Ended December 31,	
	2019	2018
	(Dollars in thousands)	
Change, net of deferred tax, in unrealized gains (losses) in respect of the Company's share in derivative instruments of unconsolidated investment.....	$ (3,417)	$ 2,235

The related accumulated loss recorded by the Company under accumulated other comprehensive income (loss) as of December 31, 2019 and 2018 was $6.3 million and $2.9 million, respectively.

The Ijen Project

For details on the Ijen project, please see Note 2 to the consolidated financial statements under the heading "Ijen transaction".

NOTE 6 — VARIABLE INTEREST ENTITIES

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

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

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

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

- Whether the Company has the power to direct the activities of the VIE that most significantly impact the entity's economic performance; and
- Whether the Company has the obligation to absorb losses of the entity that could potentially be significant to the VIE or the right to receive benefits from the entity that could potentially be significant to the VIE.

The Company's VIEs include certain of its wholly owned subsidiaries that own one or more power plants with long-term PPAs. In most cases, the PPAs require the utility to purchase substantially all of the plant's electrical output over a significant portion of its estimated useful life. Most of the VIEs have associated project financing debt that is non-recourse to the general creditors of the Company, is collateralized by substantially all of the assets of the VIE and those of its wholly owned subsidiaries (also VIEs) and is fully and unconditionally guaranteed by such subsidiaries. The Company has

concluded that such entities are VIEs primarily because the entities do not have sufficient equity at risk and/or subordinated financial support is provided through the long-term PPAs. The Company has evaluated each of its VIEs to determine the primary beneficiary by considering the party that has the power to direct the most significant activities of the entity. Such activities include, among others, construction of the power plant, operations and maintenance, dispatch of electricity, financing and strategy. Except for power plants that it acquired, the Company is responsible for the construction of its power plants and generally provides operation and maintenance services. Primarily due to its involvement in these and other activities, the Company has concluded that it directs the most significant activities at each of its VIEs and, therefore, is considered the primary beneficiary. The Company performs an ongoing reassessment of the VIEs to determine the primary beneficiary and may be required to deconsolidate certain of its VIEs in the future. The Company has aggregated its consolidated VIEs into the following categories: (i) wholly owned subsidiaries with project debt; and (ii) wholly owned subsidiaries with PPAs.

The tables below detail the assets and liabilities (excluding intercompany balances which are eliminated in consolidation) for the Company's VIEs, combined by VIE classifications, that were included in the consolidated balance sheets as of December 31, 2019 and 2018:

	December 31, 2019	
	Project Debt	PPAs
	(Dollars in thousands)	
Assets:		
Restricted cash and cash equivalents	$ 81,522	$ 20
Other current assets	164,386	29,076
Property, plant and equipment, net	1,211,656	668,891
Construction-in-process	10,188	139,642
Other long-term assets	162,995	40,138
Total assets	$ 1,630,747	$ 877,767
Liabilities:		
Accounts payable and accrued expenses	25,361	13,201
Long-term debt	794,214	—
Other long-term liabilities	126,851	32,790
Total liabilities	946,426	45,991

	December 31, 2018	
	Project Debt	PPAs
	(Dollars in thousands)	
Assets:		
Restricted cash and cash equivalents	$ 76,019	2,304
Other current assets	213,007	9,698
Property, plant and equipment, net	1,552,408	306,820
Construction-in-process	90,812	13,273
Other long-term assets	177,723	9,104
Total assets	$ 2,109,969	341,199
Liabilities:		
Accounts payable and accrued expenses	$ 24,245	2,651
Long-term debt	805,850	—
Other long-term liabilities	125,769	12,483
Total liabilities	$ 955,864	15,134

NOTE 7— FAIR VALUE OF FINANCIAL INSTRUMENTS

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

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

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

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

The following table sets forth certain fair value information at December 31, 2019 and 2018 for financial assets and liabilities measured at fair value by level within the fair value hierarchy, as well as cost or amortized cost. As required by the fair value measurement guidance, assets and liabilities are classified in their entirety based on the lowest level of inputs that is significant to the fair value measurement.

		December 31, 2019			
		Fair Value			
	Carrying Value at December 31, 2019	Total	Level 1	Level 2	Level 3
	(Dollars in thousands)				
Assets:					
Current assets:					
Cash equivalents (including restricted cash accounts)	$ 28,316	$ 28,316	$ 28,316	$ —	$ —
Derivatives:					
Contingent receivable [1]	102	102	—	—	102
Currency forward contracts [2]	362	362	—	362	—
Liabilities:					
Current liabilities:					
Derivatives:					
Contingent payables [1]	(3,359)	(3,359)	—	—	(3,359)
	$ 25,421	$ 25,421	$ 28,316	$ 362	$ (3,257)

		December 31, 2018			
		Fair Value			
	Carrying Value at December 31, 2018	Total	Level 1	Level 2	Level 3
	(Dollars in thousands)				
Assets					
Current assets:					
Cash equivalents (including restricted cash accounts)	$ 18,787	$ 18,787	$ 18,787	$ —	$ —
Derivatives:					
Contingent receivable [1]	104	104	—	—	104
Liabilities:					
Current liabilities:					
Derivatives:					
Contingent payables [1]	(3,424)	(3,424)	—	—	(3,424)
Currency forward contracts [2]	(1,040)	(1,040)	—	(1,040)	—
	$ 14,427	$ 14,427	$ 18,787	$ (1,040)	$ (3,320)

[1] These amounts relate to contingent receivables and payables and warrants pertaining to the Guadeloupe power plant purchase transaction, valued primarily based on unobservable inputs and are included within "Prepaid expenses and other", "Accounts payable and accrued expenses" and "Other long-term liabilities" on December 31, 2019 and 2018 in the consolidated balance sheets with the corresponding gain or loss being recognized within "Derivatives and foreign currency transaction gains (losses)" in the consolidated statement of operations and comprehensive income.

[2] These amounts relate to currency forward contracts valued primarily based on observable inputs, including forward and spot prices for currencies, net of contracted rates and then multiplied by notional amounts, and are included within "Receivables, other" and "Accounts payable and accrued expenses", as applicable, on December 31, 2019 and December 31, 2018, in the consolidated balance sheet with the corresponding gain or loss being recognized within "Derivatives and foreign currency transaction gains (losses)" in the consolidated statement of operations and comprehensive income.

The amounts set forth in the tables above include investments in debt instruments and money market funds (which are included in cash equivalents). Those securities and deposits are classified within Level 1 of the fair value hierarchy because they are valued using quoted market prices in an active market.

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

Derivatives not designated as hedging instruments	Location of recognized gain (loss)	Amount of recognized gain (loss)		
		2019	2018	2017
		(Dollars in thousands)		
Put options on natural gas price	Derivative and foreign currency transaction gains (losses)	$ —	$ —	$ (350)
Contingent considerations	Derivative and foreign currency transaction gains (losses)	—	170	(129)
Contingent considerations	General and administrative expenses	—	10,322	2,048
Currency forward contracts	Derivative and foreign currency transaction gains (losses)	2,556	(3,081)	3,699
		$ 2,556	$ 7,411	$ 5,268

In January 2017, the Company entered into Henry Hub Natural Gas Future contracts under which it has bought a number of put options covering a notional quantity of approximately 4.1 million British Thermal Units ("MMBtu") with exercise prices of $3 and expiration dates ranging from January 26, 2017 until November 27, 2017 in order to reduce its exposure to fluctuations in natural gas prices under its PPAs with Southern California Edison. The Company paid an aggregate amount of approximately $0.7 million for these put options. The put option contracts have monthly expiration dates at which the options can be called and the transaction would be settled on a net cash basis.

The foregoing forward and put options transactions have not been designated as hedge transactions and are marked to market with the corresponding gains or losses recognized within "Derivatives and foreign currency transaction gains (losses)" in the consolidated statements of operations and comprehensive income.

There were no transfers of assets or liabilities between Level 1, Level 2 and Level 3 during the year ended December 31, 2019.

The fair value of the Company's long-term debt approximates its fair value, except for the following:

	Fair Value		Carrying Amount	
	2019	2018	2019	2018
	(Dollars in millions)		(Dollars in millions)	
Olkaria III Loan – OPIC	$ 202.1	$ 211.8	$ 192.6	$ 210.6
Olkaria III plant 4 Loan – DEG 2	43.8	47.2	42.5	47.5
Olkaria III plant 1 Loan – DEG 3	38.8	—	37.1	—
Platanares Loan – OPIC	115.3	119.1	104.5	112.7
Amatitlan Loan	26.4	29.9	26.3	29.8
Senior Secured Notes:				
OrCal Geothermal Inc. ("OrCal")	—	19.0	—	18.7
OFC 2 LLC ("OFC 2")	210.9	214.5	203.0	217.8
Don A. Campbell 1 ("DAC 1")	78.5	78.8	78.2	83.3
USG Prudential – NV	30.6	29.4	28.4	27.8
USG Prudential – ID	18.6	18.6	19.6	18.9
USG DOE	45.0	48.3	40.8	51.4
Senior Unsecured Bonds	205.7	199.4	204.3	204.3
Senior Unsecured Loan	161.3	102.2	150.0	100.0
Plumstriker	21.7	—	21.6	—
Other long-term debt	16.3	5.4	17.4	6.2

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

The carrying value of other financial instruments, such as revolving lines of credit, commercial paper and deposits approximates fair value.

The following table presents the fair value of financial instruments as of December 31, 2019:

	Level 1	Level 2	Level 3	Total
	(Dollars in millions)			
Olkaria III – OPIC	$ —	$ —	$ 202.1	$ 202.1
Olkaria III plant 4 – DEG 2	—	—	43.8	43.8
Olkaria III plant 1 – DEG 3	—	—	38.8	38.8
Platanares Loan – OPIC	—	—	115.3	115.3
Amatitlan Loan	—	26.4	—	26.4
Senior Secured Notes:				
OFC 2 Senior Secured Notes	—	—	210.9	210.9
DAC 1 Senior Secured Notes	—	—	78.5	78.5
USG Prudential – NV	—	—	30.6	30.6
USG Prudential – ID	—	—	18.6	18.6
USG DOE	—	—	45.0	45.0
Senior Unsecured Bonds	—	—	205.7	205.7
Senior Unsecured Loan	—	—	161.3	161.3
Plumstriker	—	21.7	—	21.7
Other long-term debt	—	—	16.3	16.3
Commercial paper	—	50.0	—	50.0
Revolving lines of credit	—	40.6	—	40.6
Deposits	12.2	—	—	12.2

The following table presents the fair value of financial instruments as of December 31, 2018:

	Level 1	Level 2	Level 3	Total
	(Dollars in millions)			
Olkaria III Loan – OPIC	$ —	$ —	$ 211.8	$ 211.8
Olkaria III plant 4 – DEG 2	—	—	47.2	47.2
Platanares Loan – OPIC	—	—	119.1	119.1
Amatitlan Loan	—	29.9	—	29.9
Senior Secured Notes:				
OrCal Senior Secured Notes	—	—	19.0	19.0
OFC 2 Senior Secured Notes	—	—	214.5	214.5
DAC 1 Senior Secured Notes	—	—	78.8	78.8
USG Prudential – NV	—	—	29.4	29.4
USG Prudential – ID	—	—	18.6	18.6
USG DOE	—	—	48.3	48.3
Senior Unsecured Bonds	—	—	199.4	199.4
Senior Unsecured Loan	—	—	102.2	102.2
Other long-term debt	—	—	5.4	5.4
Revolving lines of credit	—	159.0	—	159.0
Deposits	12.0	—	—	12.0

NOTE 8 — PROPERTY, PLANT AND EQUIPMENT AND CONSTRUCTION-IN-PROCESS

Property, plant and equipment

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

	December 31,	
	2019	2018
	(Dollars in thousands)	
Land owned by the Company where the geothermal resource is located	$ 38,049	$ 38,060
Leasehold improvements	7,757	5,718
Machinery and equipment	230,465	208,646
Land, buildings and office equipment	39,099	35,708
Vehicles	8,021	22,074
Geothermal and recovered energy generation power plants, including geothermal wells and exploration and resource development costs:		
United States of America, net of cash grants	2,160,910	2,065,377
Foreign countries	721,824	710,775
Asset retirement cost	19,824	11,448
	3,225,949	3,097,806
Less accumulated depreciation	(1,254,534)	(1,138,228)
Property, plant and equipment, net	$ 1,971,415	$ 1,959,578

Depreciation expense for the years ended December 31, 2019, 2018 and 2017 amounted to $126.7 million, $114.4 million and $98.8 million, respectively. Depreciation expense for the years ended December 31, 2019, 2018, and 2017 is net of the impact of the cash grant in the amount of $7.3 million, $6.4 million and $5.5 million, respectively.

U.S. Operations

The net book value of the property, plant and equipment, including construction-in-process, located in the United States was approximately $1,841.4 million and $1,696.4 million as of December 31, 2019 and 2018, respectively. These amounts as of December 31, 2019 and 2018 are net of cash grants in the amount of $162.3 million and $179.7 million, respectively.

Foreign Operations

The net book value of property, plant and equipment, including construction-in-process, located outside of the United States was approximately $506.6 million and $524.8 million as of December 31, 2019 and 2018, respectively.

The Company, through its wholly owned subsidiary, OrPower 4, Inc. (“OrPower 4”), owns and operates geothermal power plants in Kenya. The net book value of assets associated with the power plants was $284.5 million and $302.0 million as of December 31, 2019 and 2018, respectively. The Company sells the electricity produced by the power plants to Kenya Power and Lighting Co. Ltd. (“KPLC”) under a 20-year PPA ending between 2033 and 2036 .

The Company, through its wholly owned subsidiary, Orzunil I de Electricidad, Limitada (Orzunil), owns a power plant in Guatemala. On January 22, 2014, Orzunil signed an amendment to the PPA with INDE, a Guatemalan power company, for its Zunil geothermal power plant in Guatemala. The amendment extends the term of the PPA from 2019 to 2034. The PPA amendment also transfers operation and management responsibilities of the Zunil geothermal field from INDE to the Company for the term of the amended PPA in exchange for a tariff increase. Additionally, INDE exercised its right under the PPA to become a partner in the Zunil power plant with a 3% equity interest. The net book value of the assets related to the power plant was $10.3 million and $14.6 million at December 31, 2019 and 2018, respectively.

The Company, through its wholly owned subsidiary, Ortitlan, Limitada ("Ortitlan"), owns a power plant in Guatemala. The net book value of the assets related to the power plant was $42.8 million and $43.5 million at December 31, 2019 and 2018, respectively.

The Company, through its wholly owned subsidiary, GeoPlatanares, signed a BOT contract for the Platanares geothermal project in Honduras with ELCOSA, a privately owned Honduran energy company, for 15 years from the commercial operation date, which expires in 2047. Platanares sells the electricity produced by the power plants to ENEE, the national utility of Honduras under a 30-year PPA. The net book value of the assets related to the power plant was $96.1 million and $105.7 million at December 31, 2019 and 2018, respectively.

The Company, through its subsidiary, GB, owns a power plant in Guadeloupe. The net book value of the assets related to the power plant was $24.5 million and $23.9 million at December 31, 2019 and 2018, respectively. GB sells the electricity produced by the power plants to EDF, the French electric utility, under a 15-year PPA.

Construction-in-process

Construction-in-process consists of the following:

	December 31,	
	2019	**2018**
	(Dollars in thousands)	
Projects under exploration and development:		
Up-front bonus costs	$ 17,018	$ 17,018
Exploration and development costs	66,916	53,237
Interest capitalized	703	703
	84,637	70,958
Projects under construction:		
Up-front bonus costs	27,473	27,473
Drilling and construction costs	258,484	160,398
Interest capitalized	5,961	2,861
	291,918	190,732
Total	$ 376,555	$ 261,690

	Projects under exploration and development			
	Up-front Bonus Costs	**Exploration and Development Costs**	**Interest Capitalized**	**Total**
	(Dollars in thousands)			
Balance at December 31, 2016	$ 17,385	$ 36,359	$ 703	$ 54,447
Cost incurred during the year	—	11,224	—	11,224
Write off of unsuccessful exploration costs	(367)	(1,429)	—	(1,796)
Balance at December 31, 2017	17,018	46,154	703	63,875
Cost incurred during the year	—	7,209	—	7,209
Write off of unsuccessful exploration costs	—	(126)	—	(126)
Balance at December 31, 2018	17,018	53,237	703	70,958
Cost incurred during the year	—	17,215	—	17,215
Transfer of projects under exploration and development to projects under construction	—	(3,536)	—	(3,536)
Balance at December 31, 2019	$ 17,018	$ 66,916	$ 703	$ 84,637

	Projects under construction			
	Up-front Bonus Costs	Drilling and Construction Costs	Interest Capitalized	Total
	(Dollars in thousands)			
Balance at December 31, 2016	$ 37,713	$ 202,211	$ 12,338	$ 252,262
Cost incurred during the year	—	231,926	7,300	239,226
Transfer of completed projects to property, plant and equipment	(10,240)	(235,194)	(16,387)	(261,821)
Balance at December 31, 2017	27,473	198,943	3,251	229,667
Cost incurred during the year	—	219,610	—	219,610
Cost write off	—	(1,380)	—	(1,380)
Fair value of projects under construction acquired in a business combination	—	4,668	—	4,668
Transfer of completed projects to property, plant and equipment	—	(261,443)	(390)	(261,833)
Balance at December 31, 2018	27,473	160,398	2,861	190,732
Cost incurred during the year	—	264,137	3,100	267,237
Transfer of projects under exploration and development to projects under construction	—	3,536	—	3,536
Insurance recoveries	—	(35,435)	—	(35,435)
Transfer of completed projects to property, plant and equipment	—	(134,152)	—	(134,152)
Balance at December 31, 2019	$ 27,473	$ 258,484	$ 5,961	$ 291,918

NOTE 9 — INTANGIBLE ASSETS AND GOODWILL

Intangible assets amounting to $186.2 million and $199.9 million consist mainly of the Company's PPAs acquired in business combinations and its storage activities, net of accumulated amortization of $74.1 million and $61.5 million as of December 31, 2019 and 2018, respectively. Intangible assets relating to the Company's storage activities as of December 31, 2019 and 2018 amounted to $30.2 million and $32.2 million, net of accumulated amortization of $5.4 million and $3.4 million, respectively. Amortization expense for the years ended December 31, 2019, 2018 and 2017 amounted to $13.3 million, $11.2 million and $6.9 million, respectively. Additions to intangible assets for the years ended December 31, 2019, 2018 and 2017, amounted to $0.0 million, $127.0 million and $35.6 million, respectively. The additions to intangible assets in 2018 and 2017 primarily relate to the USG and Viridity acquisitions, respectively. The Company tested the intangible assets for recoverability in December 2019 and 2018 and assessed whether there are events or change in circumstances which may indicate that the intangible assets are not recoverable. The Company's assessment resulted in that there were no write-offs of intangible assets in 2019, 2018 and 2017.

Estimated future amortization expense for the intangible assets as of December 31, 2019 is as follows:

	(Dollars in thousands)
Year ending December 31:	
2020	$ 12,983
2021	12,983
2022	12,729
2023	12,610
2024	11,255
Thereafter	123,660
Total	$ 186,220

Goodwill

Goodwill amounting to $20.1 million and $20.0 million as of December 31, 2019 and 2018, respectively, represents the excess of the fair value of considerations transferred in business combination transactions over the fair value of tangible and intangible assets acquired, net of the fair value of liabilities assumed and non-controlling interest (as applicable) in the acquisitions.

During the fourth quarter of 2018, the Company determined that certain qualitative indicators of a potential impairment existed in relation to its storage and energy management services reporting unit which required further quantitative assessment of goodwill impairment (step one as described in Note 1 to the consolidated financial statements under the caption "Goodwill"). The qualitative indicators included a significant update to the reporting unit's business forecasts combined with a large-scale restructuring of the way the Company runs this reporting unit which were both executed during the fourth quarter of 2018. As a result of the quantitative assessment, the Company recorded a goodwill impairment charge of $13.5 million in the consolidated statements of operations and comprehensive income (loss) for the year ended December 31, 2018. Following this impairment charge, the goodwill allocated to the storage and energy management services reporting unit is zero. The Company estimated the fair value of the storage and energy management services reporting unit by using the income approach based on discounted cash flows, which utilized Level 3 measurement that represent unobservable inputs into the Company's valuation method.

Except as noted above, for the years 2019, 2018 and 2017 the Company's impairment assessment related to the Company's other reporting units for which goodwill (all of which is in the Electricity segment) is allocated to resulted in no impairment to goodwill.

Changes in the carrying amount of the Company's goodwill for the years ended December 31, 2019 and 2018 were as follows:

	2019	2018
	(Dollars in thousands)	
Goodwill as of January 1,	$ 19,950	$ 21,037
Goodwill acquired	—	12,710
Goodwill impairment charge	—	(13,464)
Translation differences	190	(333)
Goodwill as of December 31,	$ 20,140	$ 19,950

NOTE 10 — ACCOUNTS PAYABLE AND ACCRUED EXPENSES

Accounts payable and accrued expenses consist of the following:

	December 31,	
	2019	2018
	(Dollars in thousands)	
Trade payable	$ 73,271	$ 56,299
Salaries and other payroll costs	24,364	20,188
Customer advances	2,092	918
Accrued interest	6,321	5,914
Income tax payable	11,344	8,436
Property tax payable	3,033	2,999
Scheduling and transmission	2,264	595
Royalty accrual	6,457	4,610
Deferred revenues	—	2,300
Warranty accrual	3,245	4,552
Other	9,466	9,551
Total	$ 141,857	$ 116,362

NOTE 11 — LONG-TERM DEBT, CREDIT AGREEMENTS AND COMMERCIAL PAPER

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

	December 31,	
	2019	2018
	(Dollars in thousands)	
Limited and non-recourse agreements:		
Loans:		
Non-recourse:		
Other loans	$ 8,997	$ 6,241
Limited recourse:		
Loan agreement with OPIC (the Olkaria III power plant)	192,646	210,641
Loan agreement with OPIC (the Platanares power plant)	104,459	112,652
Loan agreement with Banco Industrial S.A. and Westrust Bank (International) Limited	26,250	29,750
Loan agreement with a global industrial company (the Plumstriker battery energy storage projects)	21,615	—
Other loans	8,367	—
Senior Secured Notes:		
Non-recourse:		
OrCal Senior Secured Notes	—	18,652
DAC 1 Senior Secured Notes	78,247	83,319
Limited recourse:		
OFC 2 Senior Secured Notes	203,040	217,810
Other loans	88,840	96,482
Total limited and non-recourse agreements	732,461	775,547
Less current portion	(58,932)	(63,180)
Non current portion	$ 673,529	$ 712,367
Full recourse agreements:		
Senior Unsecured Bonds	204,332	204,332
Senior Unsecured Loan (Migdal)	150,000	100,000
Loan agreements with DEG (the Olkaria III and power plants 4 and 1 upgrade)	79,632	47,500
Revolving credit lines with banks	40,550	159,000
Total full recourse agreements	474,514	510,832
Less current portion	(117,122)	(164,000)
Non current portion	$ 357,392	$ 346,832

Loan Agreement with Banco Industrial S.A. and Westrust Bank (International) Limited

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

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

There are various restrictive covenants under the Amatitlan credit agreement. These include, among other things, (i) a financial covenant to maintain a Debt Service Coverage Ratio (as defined in the credit agreement) of not less than 1.15 to 1.00 as of the last day of any fiscal quarter and (ii) limitations on Restricted Payments (as defined in the credit agreement) that among other things would limit dividends that could be paid to us unless the historical and projected Debt Service Coverage Ratio is not less than 1.25 to 1.00 for the four fiscal quarterly periods (calculated as a single accounting period). As of December 31, 2019, the covenants have been met. The credit agreement includes various events of default that would permit acceleration of the loan (subject in some cases to grace and cure periods). These include, among other things, a Change of Control (as defined in the credit agreement) and failure to maintain certain required balances in debt service and maintenance reserve accounts. The credit agreement includes certain equity cure rights for failure to maintain the Debt Service Coverage Ratio and the minimum amounts required in the debt service and maintenance reserve accounts.

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

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

As of December 31, 2019, $26.3 million of this loan was outstanding.

Finance Agreement with OPIC (the Olkaria III Complex)

On August 23, 2012, OrPower 4, the Company's wholly owned subsidiary, entered into a Finance Agreement with OPIC, an agency of the U.S. government, to provide limited-recourse senior secured debt financing in an aggregate principal amount of up to $310.0 million (the "OPIC Loan") for the refinancing and financing of the Olkaria III geothermal power complex in Kenya. The Finance Agreement was amended on November 9, 2012.

The OPIC Loan is comprised of up to three tranches:

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

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

- Tranche III in an aggregate principal amount of $45.0 million was used to fund the construction of Plant 3 of the Olkaria III complex. In November 2013, an amount of $45.0 million was disbursed under this Tranche.

In July 2013, the Company completed the conversion of the interest rate applicable to both Tranche I and Tranche II from a floating interest rate to a fixed interest rate. The average fixed interest rate for Tranche I, which has an outstanding balance as of December 31, 2019 of $51.9 million and matures on December 15, 2030, and Tranche II, which has an outstanding balance as of December 31, 2019 of $111.2 million and matures on June 15, 2030, is 6.29%. In November 2013, the Company fixed the interest rate for Tranche III. The fixed interest rate for Tranche III, which has an outstanding balance as of December 31, 2019 of $29.6 million and matures on December 15, 2030, is 6.12%.

OrPower 4 has a right to make voluntary prepayments of all or a portion of the OPIC Loan subject to prior notice, minimum prepayment amounts, and a prepayment premium of 2.0% in the first two years after the Plant 2 commercial operation date, declining to 1% in the third year after the Plant 2 commercial operation date, and without premium thereafter, plus a redemption premium. In addition, the OPIC Loan is subject to customary mandatory prepayment in the event of certain reductions in generation capacity of the power plants, unless such reductions will not cause the projected ratio of cash flow to debt service to fall below 1.7.

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

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

There are various restrictive covenants under the OPIC Loan, which include a required historical and projected 12-month DSCR of not less than 1.4 (measured as of March 15, June 15, September 15 and December 15 of each year). If OrPower 4 fails to comply with these financial ratios it will be prohibited from making distributions to its shareholders. In addition, if the DSCR falls below 1.1, subject to certain cure rights, such failure will constitute an event of default by OrPower 4. This covenant in respect of Tranche I became effective on December 15, 2014. As of December 31, 2019, the covenants have been met.

As of December 31, 2019, $192.6 million of the OPIC Loan was outstanding.

Debt service reserve

As required under the terms of the OPIC Loan, OrPower 4 maintains an account which may be funded by cash or backed by letters of credit in an amount sufficient to pay scheduled debt service amounts, including principal and interest, due under the terms of the OPIC Loan in the following six months. This restricted cash account is classified as current in the consolidated balance sheets. As of December 31, 2019 and 2018, the balance of the account was $2.5 million and $2.6 million, respectively. In addition, as of December 31, 2019, part of the required debt service reserve was backed by a letter of credit in the amount of $15.6 million (see Note 22).

Well drilling reserve

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

Finance Agreement with OPIC (the Platanares power plant)

On April 30, 2018, Geotérmica Platanares, S.A. de C.V. ("Platanares"), a Honduran sociedad anónima de capital variable and an indirect subsidiary of Ormat Technologies, Inc., entered into a Finance Agreement (the "Finance Agreement") with OPIC, pursuant to which OPIC will provide to Platanares senior secured non-recourse debt financing in an aggregate principal amount of up to $124.7 million (the "Platanares Loan"), the proceeds of which will be used principally for the refinancing and financing of the Platanares 35 MW geothermal power plant located in western Honduras (the "Project"). The finance agreement was amended and closed in October of 2018.

Tranche I in an aggregate principal amount of $114.7 million was drawn in October 2018, carries a fixed interest rate of 7.02% per annum and matures in September of 2032. The closing of tranche II of up to $10 million is expected in 2020 subject to the satisfaction or waiver of certain conditions precedent.

Under the Finance Agreement, Platanares may, upon prior written notice to OPIC, make voluntary prepayments of the OPIC Loan, in whole or in part, in a minimum partial prepayment amount of $5 million together with payment to OPIC of all accrued but unpaid interest on the principal amount of the OPIC Loan to be prepaid, plus a prepayment premium. The prepayment premium is equal to (i) 2% of the principal amount of the OPIC Loan to be prepaid for any voluntary prepayment in the first or second year following expiration of the Commitment Period (as defined in the Finance Agreement) and (ii) 1% of the principal amount of the Platanares Loan to be prepaid for any voluntary prepayment in the third year following expiration of the Commitment Period. There is no prepayment premium for any voluntary prepayment in the fourth year following expiration of the Commitment Period or thereafter.

The OPIC Loan is also subject to customary mandatory prepayment upon the occurrence of certain events, including, among others, (i) receipt by Platanares of compensation or damages following a dispute that results in a material adverse change to the primary power purchase agreement for the Project, (ii) receipt by Platanares of a termination or indemnity payment from a third party (other than OPIC) or expropriation proceeds from a governmental authority upon the termination of any project documents or the condemnation, nationalization, seizure or expropriation of all or a substantial portion of the Project or property of Platanares by a governmental authority, respectively, and (iii) receipt by Platanares of sale proceeds in excess of a certain threshold from the disposition of all or any part of the property of Platanares, subject to certain exceptions.

The OPIC Loan will be secured by a first priority lien on all of the assets and ordinary shares of Platanares. The Finance Agreement contains various restrictive covenants applicable to Platanares, among others (i) to maintain a projected and historic debt service coverage ratio of no less than 1.1 to 1; (ii) to maintain on deposit in a debt service reserve account and well reserve account funds or assets with a value in excess of a minimum threshold and (iii) covenants that restrict Platanares from making certain payments or other distributions to its equity holders unless the projected and historic debt service coverage ratio is not less than 1.2 to 1. As of December 31, 2019, the covenants have been met.

The Finance Agreement also contains customary events of default, including, among others, failure to pay principal, interest or other amounts when due, non-payment or acceleration of other indebtedness of Platanares, the occurrence of a change of control of Platanares without the prior approval of OPIC, expropriation, judgments rendered against Platanares in excess of a certain threshold, failure to comply with covenants, a voluntary abandonment of the Project and the occurrence of certain bankruptcy events, subject to various exceptions and applicable notice, cure and grace periods.

As of December 31, 2019, $104.5 million of the Platanares OPIC Loan was outstanding.

Debt service reserve

As required under the terms of the Platanares Loan, Platanares maintains an account which may be funded by cash or backed by letters of credit in an amount sufficient to pay scheduled debt service amounts, including principal and interest, due under the terms of the Platanares Loan in the following six months (or nine months in case of overdue payments by the offtaker up to a certain agreed threshold). This restricted cash account is classified as current in the consolidated balance sheets. As of December 31, 2019, the balance of the account was $3.6 million and it is backed by a letter of credit in the amount of $8.1 million (see Note 22).

Well drilling reserve

As required under the terms of the Finance Agreement, Platanares is required to maintain an account which may be funded by cash or backed by letters of credit to reserve funds for well costs, based on certain determinations. As of December 31, 2019, the balance of the account was $0.0 million and was backed by a letter of credit in the amount of $2.0 million (see Note 22).

OrCal Senior Secured Notes

In December 2005, OrCal, the Company's wholly owned subsidiary, issued $165.0 million, 6.21% Senior Secured Notes ("OrCal Senior Secured Notes") and received net cash proceeds of approximately $161.1 million, after deduction of issuance costs of approximately $3.9 million. The OrCal Senior Secured Notes have been rated BBB- by Fitch Ratings. The OrCal Senior Secured Notes had a final maturity date of December 30, 2020. Principal and interest on the OrCal Senior Secured Notes were payable in semi-annual payments. The OrCal Senior Secured Notes were collateralized by substantially all of the assets of OrCal, and those of its subsidiaries and were fully and unconditionally guaranteed by all of the wholly

owned subsidiaries of OrCal. In October 2019, the Company fully prepaid the outstanding amount of $15.0 million of the OrCal Senior Secured Notes plus an additional make-whole premium of $0.4 million.

OFC 2 Senior Secured Notes

In September 2011, OFC 2, the Company's wholly owned subsidiary and OFC 2's wholly owned project subsidiaries (collectively, the "OFC 2 Issuers") entered into a note purchase agreement (the "Note Purchase Agreement") with OFC 2 Noteholder Trust, as purchaser, John Hancock Life Insurance Company (U.S.A.), as administrative agent, and the DOE, as guarantor, in connection with the offer and sale of up to $350.0 million aggregate principal amount of OFC 2 Senior Secured Notes ("OFC 2 Senior Secured Notes") due December 31, 2034.

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

On October 31, 2011, the OFC 2 Issuers completed the sale of $151.7 million in aggregate principal amount of 4.687% Series A Notes due 2032 (the "Series A Notes"). The net proceeds from the sale of the Series A Notes, after deducting transaction fees and expenses, were approximately $141.1 million, and were used to finance a portion of the construction costs of Phase I of the McGinness Hills and Tuscarora power plants and to fund certain reserves. Principal and interest on the Series A Notes are payable quarterly in arrears on the last day of March, June, September and December of each year.

On June 20, 2014, Phase 1 of Tuscarora Facility achieved Project Completion under the Note Purchase Agreement. In accordance with the terms of the Note Purchase Agreement and following recalibration of the financing assumptions, the loan amount was adjusted through a principal prepayment of $4.3 million.

On August 29, 2014, OFC 2 sold $140.0 million of OFC 2 Senior Secured Notes (the "Series C Notes") to finance the construction of the second phase of the McGinness Hills project. The Series C Notes are the last tranche under the Note Purchase Agreement with John Hancock Life Insurance Company and are 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 Series C Notes, which mature in December 2032, carry a 4.61% coupon with principal to be repaid on a quarterly basis.

The OFC 2 Senior Secured Notes are collateralized by substantially all of the assets of OFC 2 and those of its wholly owned subsidiaries and are fully and unconditionally guaranteed by all of the wholly owned subsidiaries of OFC 2. There are various restrictive covenants under the OFC 2 Senior Secured Notes, which include limitations on additional indebtedness of OFC 2 and its wholly owned subsidiaries. Failure to comply with these and other covenants will, subject to customary cure rights, constitute an event of default by OFC 2. In addition, there are restrictions on the ability of OFC 2 to make distributions to its shareholders.

Among other things, the distribution restrictions include a historical debt service coverage ratio requirement of at least 1.2 (on a blended basis for all OFC 2 power plants), measured, at the time of any proposed distribution, over each of the two six-months periods comprised of distinct consecutive fiscal quarters immediately preceding the proposed distribution, and a projected future DSCR requirement of at least 1.5 (on a blended basis for all OFC 2 power plants), measured, at the time of any proposed distribution, over each of the two six-months periods comprised of distinct consecutive fiscal quarters immediately following such proposed distribution. As of December 31, 2019, the covenants have been met.

As of December 31, 2019, $203.0 million of the OFC 2 Senior Secured Notes were outstanding.

The Company provided a guaranty in connection with the issuance of the Series A Notes and Series C Notes. The guaranty may be drawn in the event of, among other things, 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 guarantee may also be drawn if there is a payment default on the OFC 2 Senior Secured Notes or upon the occurrence of certain fundamental defaults that result in the acceleration of the OFC 2 Senior Secured Notes, in each case, prior to the date that the relevant facility(ies) financed by such OFC 2 Senior Secured Notes reaches completion and meets the applicable operational performance levels. The Company's liability under the guaranty with respect to the non-performance trigger is limited to an amount equal to the prepayment amount on the OFC 2 Senior Secured Notes necessary to bring the OFC 2 Issuers into compliance with certain coverage ratios. The Company's liability under the guarantee with respect to the other trigger event described above is not so limited.

Debt service reserve; other restricted funds

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

(i) A debt service reserve account which may be funded by cash or backed by letters of credit (see below) in an amount sufficient to pay scheduled debt service amounts, including principal and interest, due under the terms of the OFC 2 Senior Secured Notes in the following six months. This restricted cash account is classified as current in the consolidated balance sheet. As of December 31, 2019, part of the required debt service reserve was backed by a letter of credit in the amount of $19.5 million (see Note 22).

(ii) A performance level reserve account, intended to provide additional security for the OFC 2 Senior Secured Notes, which may be funded by cash or backed by letters of credit. This reserve builds up over time and reduces gradually each time the project achieves certain milestones. Upon issuance of the Series A Notes, this reserve was funded in the amount of $28.0 million. As of December 31, 2019, the balance of such account was zero million, and no letter of credit was required to be issued.

(iii) Under the terms of the OFC 2 Senior Secured Notes, OFC 2 is also required to maintain a well field drilling and maintenance reserve that builds up over time and is dedicated to costs and expenses associated with drilling and maintenance of the project's well field, which may be funded by cash or backed by letters of credit.

(iv) A performance level reserve account for McGinness Hills Phase II, intended to provide additional security for the OFC 2 Senior Secured Notes, which may be funded by cash or backed by letters of credit. As of December 31, 2019, there was no requirement for an additional security to be issued as the project was completed.

Don A. Campbell Senior Secured Notes — Non-Recourse

On November 29, 2016, ORNI 47 LLC ("ORNI 47"), the Company's subsidiary, entered into a note purchase agreement (the "ORNI 47 Note Purchase Agreement") with MUFG Union Bank, N.A., as collateral agent, Munich Reinsurance America, Inc. and Munich American Reassurance Company (the "Purchasers") pursuant to which ORNI 47 issued and sold to the Purchasers $92.5 million aggregate principal amount of its 4.03% Senior Secured Notes due September 27, 2033 (the "DAC 1 Senior Secured Notes") in a private placement exempt from the registration requirements of the Securities Act of 1933, as amended. ORNI 47 is the owner of the first phase of the Don A. Campbell geothermal power plant ("DAC 1"), and part of the ORPD LLC ("ORPD") portfolio.

The net proceeds from the sale of the DAC 1 Senior Secured Notes, after deducting certain transaction expenses and the funding of a debt service reserve account, were approximately $87.1 million and ORNI 47 used the proceeds from the sale of the Notes to refinance the development and construction costs of the DAC 1 geothermal power plant, which were originally financed using equity.

ORNI 47 began paying a scheduled amount of principal of the DAC 1 Senior Secured Notes on December 27, 2016 and now makes principal payments quarterly, on the 27th day of each March, June, September and December, until the DAC 1 Senior Secured Notes mature.

The DAC 1 Senior Secured Notes constitute senior secured obligations of ORNI 47 and are secured by all of the assets of ORNI 47. Under the ORNI 47 Note Purchase Agreement, ORNI 47 may prepay at any time all, or from time to time any part of, the DAC 1 Senior Secured Notes in an amount equal to at least $2 million or such lesser amount as may remain outstanding under the DAC 1 Senior Secured Notes at 100% of the principal amount to be prepaid plus the applicable make-whole amount determined for the prepayment date with respect to such principal amount. Upon the occurrence of a Change of Control (as defined in the ORNI 47 Note Purchase Agreement), ORNI 47 must make an offer to each holder of DAC 1 Senior Secured Notes to repurchase all of the holder's notes at 101% of the aggregate principal amount of such notes to be repurchased plus accrued and unpaid interest, if any, on such notes to, but not including, the date of repurchase. Each holder of DAC 1 Senior Secured Notes may accept such offer in whole or in part. In certain events, including certain asset sales outside the ordinary course of business, ORNI 47 must make mandatory prepayments of the DAC 1 Senior Secured Notes at 100% of the principal amount to be prepaid. The ORNI 47 Note Purchase Agreement requires ORNI 47 to comply with certain covenants, including, among others, restrictions on the incurrence of indebtedness or liens, amendment or modification of material project documents, the ability of ORNI 47 to merge or consolidate with another entity. The ORNI 47 Note Purchase Agreement also contains customary events of default. In addition, there are restrictions on the ability of ORNI 47 to make distributions to its shareholders, which include a required historical and projected DSCR of not less than 1.20 for the four fiscal quarterly periods. As of December 31, 2019, the covenants have been met.

As of December 31, 2019, $78.2 million is outstanding under the DAC 1 Senior Secured Notes.

Loans assumed with the acquisition of USG

On April 24, 2018, the Company completed the acquisition of USG. As part of the acquisition the Company assumed the following non-recourse loans:

Prudential Capital Group – Idaho non-recourse

In May 2016, USG's wholly owned subsidiary (Idaho USG Holdings LLC) entered into a loan agreement with the Prudential Capital Group to finance its development activities. The original principal totaled $20.0 million and included the option to issue additional debt up to $50.0 million within the following two years. The $20.0 million loan amount bears interest at a fixed interest rate of 5.8% per annum. The principal and interest payments are due semi-annually and the principal is partially repaid during the first seven-year term and the remaining balance of $16.0 million is due in full at the end of this seven-year term. The loan is secured by the Company's ownership interests in the Neal Hot Springs project and the Raft River project projects. As of December 31, 2019, $18.3 million of the Prudential Capital loan is outstanding.

U.S. Department of Energy – non-recourse

On August 31, 2011, USG's wholly owned subsidiary, USG Oregon LLC ("USG Oregon"), completed the first funding drawdown associated with the U.S. Department of Energy ("DOE") $96.8 million loan guarantee ("Loan Guarantee") to construct its power plant at Neal Hot Springs project in Eastern Oregon. All loan advances covered by the Loan Guarantee have been made under the Future Advance Promissory Note dated February 23, 2011. In connection with the Loan Guarantee, the DOE has been granted a security interest in all of the equity interests of USG Oregon, as well as in the assets of USG Oregon, including a mortgage on real property interests relating to the Neal Hot Springs site. No additional advances are allowed under the terms of the loan. A total of 13 draws were taken and each individual draw or tranche is considered to be a separate loan. The loan principal is scheduled to be paid over 21.5 years from the first scheduled payment date with semi-annual installments including interest calculated at an aggregate fixed interest rate of 2.6%. The principal payment amounts are calculated on a straight-line basis according to the life of the loans and the original loan principal amounts. As of December 31, 2019, $44.9 million of the DOE loan is outstanding.

Prudential Capital Group – Nevada non-recourse

On September 26, 2013, USG's wholly owned subsidiary (USG Nevada LLC) entered into a note purchase agreement with the Prudential Capital Group to finance the Phase I of San Emidio geothermal project located in northwest Nevada. The term of the note is approximately 24 years and bears interest at a fixed rate of 6.75% per annum. Interest payments are due quarterly. Principal payments are due quarterly based upon minimum debt service coverage ratios established according to projected operating results made at the loan origination date and available cash balances. The loan agreement is secured by USG Nevada LLC's right, title and interest in and to its real and personal property, including the San Emidio project and the equity interests in USG Nevada LLC. As of December 31, 2019, $27.1 million of the loan is outstanding.

Senior Unsecured Bonds

In September 2016, the Company concluded an auction tender and accepted subscriptions for two series of senior unsecured bonds comprised of approximately $67.0 million aggregate principal amount of senior unsecured bonds (the "Series 2 Bonds") and approximately $137.0 million aggregate principal amount of senior unsecured bonds (the "Series 3 Bonds" and together with the Series 2 Bonds, the "Senior Unsecured Bonds"). The proceeds from the Series 2 Bonds and Series 3 Bonds were used on September 29, 2016 to prepay the Company's $250.0 million aggregate principal amount of previously issued bonds that were payable on August 1, 2017.

The Series 2 Bonds will mature in September 2020 and bear interest at a fixed rate of 3.7% per annum, payable semi-annually. The Series 3 Bonds will mature in September 2022 and bear interest at a fixed rate of 4.45% per annum, payable semi-annually. The Series 2 Bonds and Series 3 Bonds will be repaid at maturity in a single bullet payment, unless earlier prepaid by the Company pursuant to the terms and conditions of the trust instrument that governs such Senior Unsecured Bonds.

Senior Unsecured Loan

On March 22, 2018 the Company entered into a definitive loan agreement (the "Migdal Loan Agreement") with Migdal Insurance Company Ltd., Migdal Makefet Pension and Provident Funds Ltd. and Yozma Pension Fund of Self-Employed Ltd., all entities within the Migdal Group, a leading Israeli insurance company and institutional investor in Israel. The Migdal Loan Agreement provides for a loan by the lenders to the Company in an aggregate principal amount of $100.0 million (the "Migdal Loan"). The Migdal Loan will be repaid in 15 semi-annual payments of $4.2 million each, commencing on September 15, 2021, with a final payment of $37.0 million on March 15, 2029. The Migdal Loan bears interest at a fixed rate of 4.8% per annum, payable semi-annually, subject to adjustment in certain circumstances as described below.

The Loan is subject to early redemption by the Company prior to maturity from time to time (but not more frequently than once per quarter) and at any time in whole or in part, at a redemption price set forth in the Migdal Loan Agreement. If the rating of the Company is downgraded to "ilA-"(or equivalent), of any of Standard and Poor's, Moody's or Fitch (whenever in Israel or outside of Israel) (each a "Credit Rating Agency"), the interest rate applicable to the Migdal Loan will increase by 0.50%. If the rating of the Company is further downgraded to a lower level by any Credit Rating Agency, the interest rate applicable to the Migdal Loan will be increased by 0.25% for each additional downgrade. In no event will the cumulative increase in the interest rate applicable to the Loan exceed 1% regardless of the cumulative rating downgrade. A subsequent upgrade or reinstatement of a rating by any Credit Rating Agency will reduce the interest rate applicable to the Migdal Loan by 0.25% for each upgrade (but in no event will the interest rate applicable the Migdal Loan fall below the base interest rate of 4.8%). Additionally, if the ratio between short-term and long-term debt to financial institutions and bondholders, deducting cash and cash equivalents to EBITDA is equal to or higher than 4.5, the interest rate on all amounts then outstanding under the Migdal Loan shall be increased by 0.5% per annum over the interest rate then-applicable to the Migdal Loan.

The Migdal Loan constitutes senior unsecured indebtedness of the Company and will rank equally in right of payment with any existing and future senior unsecured indebtedness of the Company, and effectively junior to any existing and future secured indebtedness, to the extent of the security therefore.

The Migdal Loan Agreement includes various affirmative and negative covenants, including a covenant that the Company maintain (i) a debt to adjusted EBITDA ratio below 6, (ii) a minimum equity amount (as shown on its consolidated financial statements, excluding noncontrolling interests) of not less than $650 million, and (iii) an equity attributable to Company's stockholders to total assets ratio of not less than 25%. In addition, the Migdal Loan Agreement restricts the Company from making dividend payments if its equity falls below $800 million and otherwise restricts dividend payments in any one year to not more than 50% of the net income of the Company of such year as shown on the Company's consolidated annual financial statements as long as any of the Company's bonds issued in Israel prior to March 27, 2018 remain outstanding. The Migdal Loan Agreement includes other customary affirmative and negative covenants and events of default.

On March 25, 2019, the Company entered into a first addendum ("First Addendum") to the Migdal Loan Agreement with the Migdal Group dated March 22, 2018. The First Addendum provides for an additional loan by the lenders to the Company in an aggregate principal amount of $50.0 million (the "Additional Migdal Loan"). The Additional Migdal Loan will be repaid in 15 semi-annual payments of $2.1 million each, commencing on September 15, 2021, with a final payment of $18.5 million on March 15, 2029. The Additional Migdal Loan bears interest at a fixed rate of 4.6% per annum, payable semi-annually, subject to adjustment in certain circumstances as described below. The Additional Migdal Loan was entered into under substantially the same terms and conditions of the Migdal Loan Agreement as disclosed above.

Loan Agreements with DEG (the Olkaria III Complex)

On October 20, 2016, OrPower 4 entered into a new $50.0 million subordinated loan agreement with DEG (the "DEG 2 Loan Agreement") and on December 21, 2016, OrPower 4 completed a drawdown of the full loan amount of $50 million, with a fixed interest rate of 6.28% for the duration of the loan (the "DEG 2 Loan"). The DEG 2 Loan is being repaid in 20 equal semi-annual principal installments which commenced on December 21, 2018, with a final maturity date of June 21, 2028. Proceeds of the DEG 2 Loan were used by OrPower 4 to refinance Plant 4 of the Olkaria III Complex, which was originally financed using equity. The DEG 2 Loan is subordinated to the senior loan provided by OPIC for Plants 1-3 of the Olkaria III Complex. The DEG 2 Loan is guaranteed by the Company.

Under the DEG 2 Loan Agreement, OrPower 4 may prepay at any time all, or from time to time any part of the DEG 2 Loan in an amount equal to at least $5 million or such lesser amount as may remain outstanding under the DEG 2 Loan at 100% of the principal amount to be prepaid plus the applicable make-whole amount and certain prepayment premium amount determined for the prepayment date with respect to such principal amount. In certain events, OrPower 4 must make mandatory prepayments of the DEG 2 Loan at 100% of the principal amount to be prepaid plus the applicable make-whole amount and certain prepayment premium amount determined for the prepayment date with respect to such principal amount. The DEG 2 Loan Agreement requires OrPower 4 to comply with certain covenants, including, among others, restrictions on the incurrence of indebtedness or liens. The DEG 2 Loan Agreement also contains customary events of default.

As of December 31, 2019, $42.5 million is outstanding under the DEG 2 Loan.

DEG 3 Loan

On January 4, 2019, OrPower 4 entered into an additional $41.5 million subordinated loan agreement with Deutsche Investitions-und Entwicklungsgesellschaft mbH ("DEG") (the "DEG 3 Loan Agreement") and on February 28, 2019, OrPower 4 completed a drawdown of the full loan amount, with a fixed interest rate of 6.04% for the duration of the loan (the "DEG 3 Loan"). The DEG 3 Loan is being repaid in 19 equal semi-annual principal installments, which commenced on June 21, 2019, with a final maturity date of June 21, 2028. Proceeds of the DEG 3 Loan were used by OrPower 4 to refinance upgrades to Plant 1 of the Olkaria III Complex, which were originally financed using equity. The DEG 3 Loan is subordinated to the senior loan provided by Overseas Private Investment Corporation ("OPIC") for Plants 1-3 of the Olkaria III Complex. The DEG 3 Loan is guaranteed by the Company.

As of December 31, 2019, $37.1 million is outstanding under the DEG 3 Loan.

Plumstriker Loan

On May 4, 2019, a wholly owned indirect subsidiary of the Company ("Plumstriker") and its two subsidiaries entered into a $23.5 million loan agreement with a United States ("U.S.") financing division of a leading global industrial company for the financing of two 20 MW battery energy storage projects located in New Jersey.

On May 30, 2019, Plumstriker completed the drawdown of the full loan amount, bearing interest of three months U.S. Libor plus a 3.5% margin. The loan is being repaid in 29 equal quarterly principal installments of 1.25% of the loan, and additional 14 unequal semi-annual principal payments, which commenced on June 30, 2019. The final maturity date of the loan is May 30, 2026. Proceeds of the loan were used to refinance investments in the Plumsted and Stryker projects. The debt repayment of the loan is not guaranteed by the Company or any of its subsidiaries.

As of December 31, 2019, $21.6 million is outstanding under the Plumstriker Loan.

Société Géneralé Loan

On April 9, 2019, an indirect subsidiary of the Company ("Guadeloupe"), entered into a $8.9 million loan agreement with Société Général. On April 29, 2019, Guadeloupe completed the drawdown of the full loan amount of the loan, bearing a fixed interest rate of 1.52%. The loan is being repaid in 28 quarterly principal installments, which commenced on July 29, 2019. The final maturity date of the loan is April 29, 2026. The loan has a limited guarantee by one of the Company's subsidiaries.

As of December 31, 2019, $8.4 million was outstanding under the Société Géneralé Loan.

Bpifrance Loan

On April 4, 2019, Guadeloupe, entered into a $8.9 million loan agreement with Banque Publique d'Investissement ("Bpifrance"). On April 29, 2019, Guadeloupe completed the drawdown of the full loan amount, bearing a fixed interest rate of 1.93%. The loan will be repaid in 20 equal quarterly principal installments, commencing June 30, 2021. The final maturity date of the loan is March 31, 2026. The loan is not guaranteed by the Company or any of its other subsidiaries.

As of December 31, 2019, $9.0 million is outstanding under the Bpifrance Loan.

Revolving credit lines with commercial banks

As of December 31, 2019, the Company has credit agreements with eight commercial banks for an aggregate amount of $505.0 million (including $60.0 million from Union Bank, N.A. ("Union Bank") and $35.0 million from HSBC), as described below. Under the terms of these credit agreements, the Company, or its Israeli subsidiary, Ormat Systems Ltd. ("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 $260.0 million; and (ii) the issuance of one or more letters of credit in the amount of up to $245.0 million. The credit agreements mature between end of March 2020 and July 2022. 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, 2019, $40.6 million in loans were outstanding and letters of credit with an aggregate stated amount of $213.7 million were issued and outstanding under such credit agreements.

Credit Agreements

Credit agreement with Union Bank

In February 2012, Ormat Nevada Inc. ("Ormat Nevada"), the Company's wholly owned subsidiary, entered into an amended and restated credit agreement with Union Bank. Under the credit agreement, the credit termination date is June 30, 2020. On December 31, 2019, the aggregate amount available under the credit agreement was $60.0 million. The facility is limited to the issuance, extension, modification or amendment of letters of credit. Union Bank is currently the sole lender and issuing bank under the credit agreement, but is also designated as an administrative agent on behalf of banks that may, from time to time in the future, join the credit agreement as lenders. In connection with this transaction, the Company entered into a guarantee in favor of the administrative agent for the benefit of the banks, pursuant to which the Company agreed to guarantee Ormat Nevada's obligations under the credit agreement. Ormat Nevada's obligations under the credit agreement are otherwise unsecured.

There are various restrictive covenants under the credit agreement, which include a requirement to comply with the following financial ratios, which are measured quarterly: (i) a 12-month debt to EBITDA ratio not to exceed 4.5; (ii) 12-month DSCR of not less than 1.35; and (iii) distribution leverage ratio not to exceed 2.0. As of December 31, 2019: (i) the actual 12-month debt to EBITDA ratio was 2.1; (ii) the 12-month DSCR was 2.87; and (iii) the distribution leverage ratio was 1.0. In addition, there are restrictions on dividend distributions in the event of a payment default or noncompliance with such ratios, and subject to specified carve-outs and exceptions, a negative pledge on the assets of Ormat Nevada in favor of Union Bank.

As of December 31, 2019, letters of credit in the aggregate amount of $59.5 million remain issued and outstanding under this credit agreement with Union Bank.

Credit agreement with HSBC

In May 2013, Ormat Nevada, entered into a credit agreement with HSBC Bank USA, N.A for one year with annual renewals. The current expiration date of the facility under this credit agreement is October 31, 2020. On December 31, 2019, the aggregate amount available under the credit agreement was $35.0 million. Other than $10 million of this credit facility which may be drawn for the Company's working capital needs, this credit line is limited to the issuance, extension, modification or amendment of letters of credit. HSBC is currently the sole lender and issuing bank under the credit agreement, but is also designated as an administrative agent on behalf of banks that may, from time to time in the future, join the credit agreement as parties thereto. In connection with this transaction, the Company entered into a guarantee in favor of the administrative agent for the benefit of the banks, pursuant to which the Company agreed to guarantee Ormat Nevada's obligations under the credit agreement. Ormat Nevada's obligations under the credit agreement are otherwise unsecured.

There are various restrictive covenants under the credit agreement, including a requirement to comply with the following financial ratios, which are measured quarterly: (i) a 12-month debt to EBITDA ratio not to exceed 4.5; (ii) 12-month DSCR of not less than 1.35; and (iii) distribution leverage ratio not to exceed 2.0. As of December 31, 2019: (i) the actual 12-month debt to EBITDA ratio was 2.1; (ii) the 12-month DSCR was 2.87; and (iii) the distribution leverage ratio was 1.0. In addition, there are restrictions on dividend distributions in the event of a payment default or noncompliance with such ratios, and subject to specified carve-outs and exceptions, a negative pledge on the assets of Ormat Nevada in favor of HSBC.

As of December 31, 2019, letters of credit in the aggregate amount of $25.5 million remain issued and outstanding under this credit agreement.

CHUBB Surety Bond

In May 2017, the Company entered into a surety bond agreement (the "Surety Agreement") with Chubb Limited ("Chubb") pursuant to which the Company may request that Chubb issue up to an aggregate $200.0 million of surety bonds with respect to the contractual obligations of the Company and its subsidiaries in exchange for bank letters of credit or as otherwise may be required. There is no expiration date for the Surety Agreement, but it may be terminated by the Company at any time upon twenty days' prior written notice to Chubb. Delivery of such termination notice will not affect any surety bonds issued and outstanding prior to the date on which such notice is delivered. As of December 31, 2019, Chubb issued a surety bond in the amount of $144.8 million under the Surety Agreement.

Short-term commercial paper

On June 27, 2019, the Company entered into a framework agreement for participation in the issuance of commercial paper (the "Agreement") with Discount Capital Underwriting Ltd. under which the Company allowed the participants to submit proposals for purchasing and to purchase the Company's commercial paper ("Commercial Paper") in accordance with the provisions of the Agreement. On July 3, 2019, the Company completed the issuance of the Commercial Paper in the aggregate amount of $50.0 million. The Commercial Paper was issued for a period of 90 days and extends automatically for additional 90 day periods for up to five years, unless the Company notifies the participants otherwise or a notice of termination is provided by the participants in accordance with the provisions of the Agreement. The Commercial Paper bears an annual interest of three months LIBOR +0.75% which is paid at the end of each 90 day period. The Commercial Paper is presented under Current liabilities in the Consolidated Balance Sheets.

As of December 31, 2019, an aggregate amount of $50.0 million was issued and outstanding under this Agreement.

Restrictive covenants

The Company's obligations under the credit agreements, the loan agreements, and the trust instrument governing the bonds, described above, are unsecured, but are subject to a negative pledge in favor of the banks and the other lenders and certain other restrictive covenants. These include, among other things, a prohibition on: (i) creating any floating charge or any permanent pledge, charge or lien over the Company's 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 the Company's assets, or a change of control in the Company's ownership structure. Some of the credit agreements, the term loan agreements, as well as the trust instrument contain cross-default provisions with respect to other material indebtedness owed by us to any third party. In some cases, the Company has agreed to maintain certain financial ratios, which are measured quarterly, such as: (i) equity of at least $600.0 million and in no event less than 25% of total assets; (ii) 12-month debt, net of cash, cash equivalents marketable securities and short-term bank deposits to Adjusted EBITDA ratio not to exceed 6; and (iii) dividend distribution not to exceed 35% of net income for that year. As of December 31, 2019: (i) total equity was $1,515.4 million and the actual equity to total assets ratio was 46.6%, and (ii) the 12-month debt, net of cash, cash equivalents marketable securities and short-term bank deposits to Adjusted EBITDA ratio was 2.99. During the year ended December 31, 2019, the Company distributed interim dividends in an aggregate amount of $22.4 million.

Future minimum payments

Future minimum payments under long-term debt as of December 31, 2019 are as follows:

	(Dollars in thousands)
Year ending December 31:	
2020	$ 135,504
2021	76,259
2022	220,677
2023	98,982
2024	78,600
Thereafter	557,890
Total	$ 1,167,912

NOTE 12 — PUNA POWER PLANT TRANSACTIONS

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

In December 2019, PGV and HELCO executed an amended and restated PPA for power sold from the Puna complex power plant. The new PPA extends the term until 2052 with an increased contract capacity of 46 MW and a fixed price of $70 per MWh with no escalation all energy purchased during any contract year up to 227,000 MWh and $40 per MWh above 227,000 MWh. In addition, annual capacity payments under the contract are expected to be approximately $19.5 million. The amended and restated PPA was filed with the Public Utilities Commission on December 31, 2019.

In connection with the execution of the amended and restated PPA, the Company paid $20.5 million to effectively terminate the lease transactions involving the original power plant which gives the Company the ability to satisfy its obligations under the new PPA. The Company recorded this payment under deposits and other in its consolidated balance sheets as an incremental cost in obtaining the new amended and restated PPA as described above. As a result, the Company has no obligation for future minimum payments as of December 31, 2019.

Prior to the amended and restated PPA, PGV leased the Puna Power Plant to an unrelated company under a 31-year head lease (the "Head Lease") in return for prepaid lease payments in the total amount of $83.0 million (the "Deferred Lease Income"). The unrelated company (the "Lessor") simultaneously leased back the Puna Power Plant to PGV under a 23-year

lease (the "Project Lease"). PGV's rent obligations under the Project Lease were paid solely from revenues generated by the Puna Power Plant under a PPA that PGV had with HELCO. The Head Lease and the Project Lease were non-recourse lease obligations to the Company. PGV's rights in the geothermal resource and the related PPA were not leased to the Lessor as part of the Head Lease but are part of the Lessor's security package.

The Head Lease and the Project Lease were accounted for separately. Each was classified as an operating lease in accordance with the accounting standards for leases. The Project Lease transaction was included in the initial recognition of operating leases right of use asset and liability on the consolidated balance sheets as of January 1, 2019 as further described under Note 1 to the consolidated financial statements under the caption New Accounting Pronouncements, Leases. The Deferred Lease Income was amortized into revenue using the straight-line method, over the 31-year term of the Head Lease. Deferred transaction costs amounting to $4.2 million were amortized using the straight-line method, over the 23-year term of the Project Lease. The carrying value of the leased assets as of December 31, 2018 was $19.7 million, net of accumulated depreciation of $33.1 million.

NOTE 13 —TAX MONETIZATION TRANSACTIONS

McGinness Hills 3 tax monetization transaction

On August 14, 2019, one of the Company's wholly-owned subsidiaries that indirectly owns the 48 MW McGinness Hills phase 3 geothermal power plant entered into a partnership agreement with a private investor. Under the transaction documents, the private investor acquired membership interests in the McGinness Hills phase 3 geothermal power plant for an initial purchase price of approximately $59.3 million and for which it will pay additional installments that are expected to amount to approximately $9 million and can reach up to $22 million based on the actual generation. The Company will continue to consolidate, operate and maintain the power plant and will receive substantially all the distributable cash flow generated by the power plant and the private investor will receive substantially all of the tax attributes, as described below.

Pursuant to the transaction documents, prior to December 31, 2027 ("Target Flip Date"), one of the Company's wholly owned subsidiary receives substantially all of the distributable cash flow generated by the McGinness Hills phase 3 power plant, while the private investor receives substantially all of the tax attributes of the project. Following the later of the Target Flip Date and the date on which the private investor reaches its target return, the Company will receive 97.5% of the distributable cash generated by the power plant and 95.0% of the tax attributes, on a go forward basis. In the event that the private investor will not reach its target return by the Target Flip Date, then for the period between the Target Flip Date and the date on which the private investor reaches its target return, the private investor will receive 100% of the distributable cash generated by the power plant and 99% of the tax attributes as long as the project is generating PTCs (and 5% of the tax attributes afterwards).

On the Target Flip Date, the Company, through one of its wholly-owned subsidiaries, has the option to purchase the private investor's interests at the then-current fair market value, plus an amount that causes the private investor to reach its target return, if needed. If the Company exercises this purchase option, it will become the sole owner of the project again.

Tungsten Mountain partnership transaction

On May 17, 2018, one of the Company's wholly-owned subsidiaries that indirectly owns the 26 MW Tungsten Mountain Geothermal power plant entered into a partnership agreement with a private investor. Under the transaction documents, the private investor acquired membership interests in the Tungsten Mountain Geothermal power plant project for an initial purchase price of approximately $33.4 million and for which it will pay additional installments that are expected to amount to approximately $13 million. The Company will continue to operate and maintain the power plant and will receive substantially all the distributable cash flow generated by the power plant, as described below.

Under the transaction documents, prior to December 31, 2026 ("Target Flip Date"), the Company's wholly-owned subsidiary, Ormat Nevada Inc. ("Ormat Nevada"), receives substantially all of the distributable cash flow generated by the project, while the private investor receives substantially all of the tax attributes of the project. Following the later of the Target Flip Date and the date on which the private investor reaches its target return, Ormat Nevada will receive 97.5% of the distributable cash and 95.0% of the taxable income, on a go forward basis. In the event that the private investor will not reach its target return by the Target Flip Date, then for the period between the Target Flip Date and the date on which the private

investor reaches its target return, the private investor will receive 100% of the distributable cash generated by the power plant and 99% of the tax attributes as long as the project is generating PTCs (and 5% of the tax attributes afterwards).

On the Target Flip Date, Ormat Nevada has the option to purchase the private investor's interests at the then-current fair market value, plus an amount that causes the private investor to reach its target return, if needed. If Ormat Nevada exercises this purchase option, it will become the sole owner of the project again.

Opal Geo Transaction

On December 16, 2016, Ormat Nevada entered into an equity contribution agreement (the "Equity Contribution Agreement") with OrLeaf LLC ("OrLeaf") and JPM with respect to Opal Geo. Also on December 16, 2016, OrLeaf, a newly formed limited liability company formed by Ormat Nevada and ORPD LLC, entered into an amended and restated limited liability company agreement of Opal Geo (the "LLC Agreement") with JPM. The transactions contemplated by the Equity Contribution Agreement and LLC Agreement will allow the Company to monetize federal PTCs and certain other tax benefits relating to the operation of five geothermal power plants located in Nevada.

In connection with the transactions contemplated by the Equity Contribution Agreement and the LLC Agreement, Ormat Nevada transferred its indirect ownership interest in the McGinness Hills (Phase I and Phase II), Tuscarora, Jersey Valley and second phase of the Don A. Campbell ("DAC 2") geothermal power plants to Opal Geo. Prior to such transfer, Ormat Nevada held an approximately 63.25% indirect ownership interest in DAC 2 through ORPD LLC, a joint venture between Ormat Nevada and Northleaf Geothermal Holdings LLC ("Northleaf"), an affiliate of Northleaf Capital Partners, and held, directly or indirectly, a 100% ownership interest in the remaining geothermal power plants that were transferred to Opal Geo.

Pursuant to the Equity Contribution Agreement, JPM contributed approximately $62.1 million to Opal Geo in exchange for 100% of the Class B Membership Interests of Opal Geo. JPM also agreed to make deferred capital contributions to Opal Geo based on the amount of electricity generated by the DAC 2 and McGinness Hills Phase II power plants which are eligible for the federal PTC. The Company expects the aggregate amount of JPM's deferred capital contributions to equal approximately $21 million and to be paid over time covering the period through December 31, 2022.

Under the LLC Agreement, until December 31, 2022, OrLeaf will receive distributions of 97.5% of any distributable cash generated by operation of the power plants while JPM will receive distributions of 2.5% of any distributable cash generated by operation of the power plants. Unless JPM has already achieved its target internal rate of return on its investment in Opal Geo, from December 31, 2022 until JPM has achieved its target internal rate of return, JPM will receive 100% of any distributable cash generated by operation of the power plants. Thereafter, OrLeaf will receive distributions of 97.5%, and JPM will receive 2.5%, of any distributable cash generated by operation of the power plants.

Under the LLC Agreement, all items of Opal Geo income and loss, gain, deduction and credit (including the federal production tax credits relating to the operation of the two PTC eligible power plants) will be allocated, until JPM has achieved its target internal rate of return on its investment in Opal Geo (and for so long as the two PTC eligible power plants are generating PTCs), 99% to JPM and 1% to OrLeaf, or 5% to JPM and 95% to OrLeaf if PTCs are no longer available to either of the two PTC eligible power plants. Once JPM achieves its target internal rate of return, all items of Opal Geo income and loss, gain, deduction and credit will be allocated 5% to JPM and 95% to OrLeaf.

Under the LLC Agreement, OrLeaf, which owns 100% of the Class A Membership Interests in Opal Geo, will serve as the managing member of Opal Geo and control the day-to-day management of Opal Geo and its portfolio of five power plants. However, in certain limited circumstances (such as bankruptcy of Orleaf, fraud or gross negligence by OrLeaf) JPM may remove OrLeaf as the managing member of Opal Geo. JPM, as the Class B Member of Opal Geo, has consent and approval rights with respect to certain items that are designated as major decisions for Opal Geo and the five power plants. In addition, by virtue of certain provisions in OrLeaf's own limited liability company agreement, and consistent with the ORPD LLC formation documents, Northleaf has similar consent and approval rights with respect to OrLeaf's determination of major decisions pertaining to the DAC 2 power plant. In both cases, these major decisions are generally equivalent to customary minority protection rights. As a result, the Company's wholly owned subsidiary, Ormat Nevada, which serves as the managing member of OrLeaf and as the managing member of ORPD LLC, will effectively retain the day-to-day control and management of Opal Geo and its portfolio of five power plants.

The LLC Agreement contains certain customary restrictions on transfer applicable to both OrLeaf and JPM with respect to their respective Membership Interests in Opal Geo, and also provides OrLeaf with a right of first offer in the event JPM desires to transfer any of its Class B Membership Interests, pursuant to which OrLeaf may purchase such Class B Membership Interests. The LLC Agreement also provides OrLeaf with the option to purchase all of the Class B Membership Interests on either December 31, 2022 or the date that is 9 years after the closing date under the Equity Contribution Agreement at a price equal to the greater of (i) the fair market value of the Class B Membership Interests as of the date of purchase (subject to certain adjustments) and (ii) $3 million.

Pursuant to the Equity Contribution Agreement, the Company has provided a guaranty for the benefit of JPM of certain of OrLeaf's indemnification obligations to JPM under the LLC Agreement. In addition, Ormat Nevada also provided a guaranty for the benefit of JPM of all present and future payment and performance obligations of OrLeaf under the LLC Agreement and each ancillary document to which OrLeaf is a party.

JPM's approximately $62.1 million capital contribution to Opal Geo was recorded as a $3.7 million allocation to noncontrolling interests and a $58.5 million allocation to liability associated with sale of tax benefits as described in Note 1. JPM also agreed to make deferred capital contributions to Opal Geo based on the amount of electricity generated by the DAC 2 and McGinness Hills Phase II power plants which are eligible for the federal PTC.

Other completed tax monetization transactions

On May 31, 2017, the Company's partners JPM and Morgan Stanley achieved their target after-tax yield on its investment in OPC and on October 31, 2017, Ormat Nevada purchased all of the Class B membership units in OPC from JPM and Morgan Stanley for $1.9 million. As a result, Ormat Nevada is now the sole owner of all of the economic and voting interests in OPC and continues to consolidate OPC in its financial statements. The purchase of Class B membership units of OPC was recorded in equity as a reduction of $6.5 million to Noncontrolling Interest with the surplus of $8.5 million charged to Additional Paid-in Capital.

In March 2017, JPM achieved its target after-tax yield on its investment in ORTP and on July 10, 2017, Ormat Nevada purchased all of the Class B membership units in ORTP from JPM for $2.4 million. As a result, Ormat Nevada is now the sole owner of all of the economic and voting interests in ORTP and continues to consolidate ORTP in its financial statements. The purchase of Class B membership units of ORTP was recorded in equity as a reduction to Noncontrolling Interest of $7.0 million with the surplus of $2.9 million charged to Additional Paid-in Capital.

NOTE 14 — ASSET RETIREMENT OBLIGATION

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

	Year Ended December 31,	
	2019	2018
	(Dollars in thousands)	
Balance at beginning of year	$ 39,475	$ 27,110
Revision in estimated cash flows	(335)	(258)
Liabilities incurred and acquired	8,334	10,149
Accretion expense	2,709	2,474
Balance at end of year	$ 50,183	$ 39,475

NOTE 15 — STOCK-BASED COMPENSATION

The Company makes an estimate of expected forfeitures and recognizes compensation costs only for those stock-based awards expected to vest. As of December 31, 2019, the total future compensation cost related to unvested stock-based awards that are expected to vest is $8.4 million, which will be recognized over a weighted average period of 1.2 years.

During the years ended December 31, 2019, 2018 and 2017, the Company recorded compensation related to stock-based awards as follows:

	Year Ended December 31,		
	2019	2018	2017
	(Dollars in thousands)		
Cost of revenues	$ 3,633	$ 3,488	$ 3,369
Selling and marketing expenses	4,810	792	452
General and administrative expenses	916	5,938	4,939
Total stock-based compensation expense	9,359	10,218	8,760
Tax effect on stock-based compensation expense	736	668	604
Net effect of stock-based compensation expense	$ 8,623	$ 9,550	$ 8,156

During the fourth quarter of 2019, 2018 and 2017, the Company evaluated the trends in the stock-based award forfeiture rate and determined that the actual rates are 10.7%, 5.3% and 1.1%, respectively. This represents an increase of 101.9%, an increase of 381.8%, and a decrease of 89.3%, respectively, from prior estimates. As a result of the change in the estimated forfeiture rate, there was an immaterial impact on stock-based compensation expense for each of the respective periods.

Valuation assumptions

The Company estimates the fair value of the stock-based awards using the Exercise Multiple-Based Lattice Model as it enables a degree of accounting for the complexities of option valuation and reduces the probability of a measurement error. The dividend yield forecast is expected to be 20% of the Company's yearly net profit, which is equivalent to a 0.7% yearly weighted average dividend rate in the year ended December 31, 2019. The risk-free interest rate was based on the yield from U.S. constant treasury maturities bonds with an equivalent term. The forfeiture rate is based on trends in actual stock-based awards forfeitures.

The Company calculated the fair value of each stock-based award on the date of grant based on the following assumptions:

	Year Ended December 31,		
	2019	2018	2017
For stock based awards issued by the Company:			
Risk-free interest rates	1.8 %	2.8 %	1.9 %
Expected lives (in weighted average years)	3.5	3.5	3.1
Dividend yield	0.7 %	0.9 %	0.62 %
Expected volatility (weighted average)	25.1 %	25.5 %	27.2 %

The Company estimated the forfeiture rate (on a weighted average basis) as follows:

	Year Ended December 31,		
	2019	2018	2017
Weighted average forfeiture rate	8.6 %	3.1 %	— %

Stock-based awards

The 2012 *Incentive Compensation Plan*

In May 2012, the Company's shareholders adopted the 2012 Incentive Plan, which provides for the grant of the following types of awards: incentive stock options, non-qualified stock options, restricted stock units ("RSUs"), stock appreciation rights ("SARs"), stock units, performance awards, phantom stock, incentive bonuses, and other possible related dividend equivalents to employees of the Company, directors and independent contractors. Under the 2012 Incentive Plan, a total of 4,000,000 shares of the Company's common stock were reserved for issuance, all of which could be issued as options or as other forms of awards. Options and SARs granted to employees under the 2012 Incentive Plan typically vest and become exercisable as follows: 25% vest 24 months after the grant date, an additional 25% vest 36 months after the grant date, and

the remaining 50% vest 48 months after the grant date. Options granted to non-employee directors under the 2012 Incentive Plan will vest and become exercisable one year after the grant date. Restricted stock units granted to directors and members of senior management vest according to a vesting schedule as follows: for the directors, 100% on the first anniversary of the grant date and for members of senior management, 25% on each of the first, second, third and fourth anniversaries of the grant date. The term of stock-based awards typically ranges from six to ten years from the grant date. The shares of common stock issued in respect of awards under the 2012 Incentive Plan are issued from the Company's authorized share capital upon exercise of options or SARs. The 2012 Incentive Plan expired in May 2018 upon adoption of the 2018 Incentive Compensation Plan ("2018 Incentive Plan"), except as to stock-based awards outstanding under the 2012 Incentive Plan on that date.

The 2018 *Incentive Compensation Plan*

In May 2018, the Company held its 2018 Annual Meeting of Stockholders at which the Company's stockholders approved the 2018 Incentive Plan. The 2018 Incentive Plan provides for the grant of the following types of awards: incentive stock options, RSUs, SARs, stock units, performance awards, phantom stock, incentive bonuses and other possible related dividend equivalents to employees of the Company, directors and independent contractors. Under the 2018 Incentive Plan, a total of 5,000,000 shares of the Company's common stock were authorized and reserved for issuance, all of which could be issued as options or as other forms of awards. SARs and RSUs granted to employees under the 2018 Incentive Plan typically vest and become exercisable as follows: 50% on the second anniversary of the grant date and 25% on each of the third and fourth anniversaries of the grant date. SARs and Restricted stock units granted to directors under the 2018 Incentive Plan typically vest and become exercisable (100%) on the first anniversary of the grant date. The term of stock-based awards typically ranges from six to ten years from the grant date. The shares of common stock issued in respect of awards under the 2018 Incentive Plan are issued from the Company's authorized share capital upon exercise of options or SARs.

On November 7, 2019, the Company granted its directors an aggregate of 11,495 SARs and 9,420 RSUs under the Company's 2018 Incentive Plan. The exercise price of each SAR was $76.87 which represented the fair market value of the Company's common stock on the grant date. The SARs will expire six years from date of grant and both the SARs and RSUs will fully vest on the first anniversary of the grant date.

The fair value of each SAR and RSU for the directors on the grant date was $19.8 and $76.4, respectively. The Company calculated the fair value of each SAR on the grant date using the Exercise Multiple-Based Lattice Pricing model based on the following assumptions:

Risk-free interest rate	1.79 %
Expected life (in years)	3.5
Dividend yield	0.57 %
Expected volatility	24.80 %
Forfeiture rate for directors	0.0 %
Sub-Optimal Exercise Factor for directors	2.8

Information on the awards outstanding and the related weighted average exercise price as of and for the years ended December 31, 2019, 2018 and 2017 are presented in the table below:

	Year Ended December 31,					
	2019		2018		2017	
	Awards (In thousands)	Weighted Average Exercise Price	Awards (In thousands)	Weighted Average Exercise Price	Awards (In thousands)	Weighted Average Exercise Price
Outstanding at beginning of year	2,527	$ 46.77	1,548	$ 41.35	2,565	$ 33.36
Granted, at fair value:						
Stock Options	—	—	—	—	30	57.97
SARs*	38	69.13	1,172	53.87	132	62.55
RSUs**	9	—	74	—	23	—
Exercised	(711)	37.83	(203)	29.75	(1,181)	25.92
Forfeited	(71)	50.59	(64)	45.73	(21)	46.15
Expired	—	—	—	—	—	—
Outstanding at end of year	1,792	50.39	2,527	46.77	1,548	41.35
Options and SARs exercisable at end of year	479	48.35	846	42.06	431	32.61
Weighted-average fair value of options and SARs granted during the year		$ 29.24		$ 16.45		$ 22.82

* Upon exercise, SARs entitle the recipient to receive shares of common stock equal to the increase in value of the award between the grant date and the exercise date.

** An RSU represents the right to receive one share of common stock once certain vesting conditions are met. The value of an RSU is identical to the value of the underlying stock.

As of December 31, 2019, 3,584,485 shares of the Company's common stock are available for future grants under the 2018 Incentive Plan. No shares of the Company's common stock are available for future grants under the 2012 Incentive Plan as of such date.

The following table summarizes information about stock-based awards outstanding at December 31, 2019 (shares in thousands):

	Awards Outstanding			Awards Exercisable		
Exercise Price	Number of Stock-based Awards Outstanding	Weighted Average Remaining Contractual Life in Years	Aggregate Intrinsic Value	Number of Stock-based Awards Exercisable	Weighted Average Remaining Contractual Life in Years	Aggregate Intrinsic Value
$ —	59	1.5	$ 4,369	—	—	$ —
42.87	427	2.5	13,517	230	2.5	7,295
47.46	15	3.9	406	15	3.9	406
51.71	8	5.0	182	—	—	—
53.16	35	4.9	756	15	4.9	329
53.44	783	4.5	16,498	—	—	—
55.16	296	3.9	5,724	131	3.9	2,527
57.97	30	4.6	497	30	4.6	497
58.79	12	2.5	187	6	2.5	94
63.35	98	3.9	1,094	52	3.9	581
71.71	4	5.6	11	—	—	—
72.14	15	5.7	36	—	—	—
76.43	10	5.9	—	—	—	—
	1,792	3.8	$ 43,277	479	3.2	$ 11,729

The following table summarizes information about stock-based awards outstanding at December 31, 2018 (shares in thousands):

	Awards Outstanding			Awards Exercisable		
Exercise Price	Number of Stock-based Awards Outstanding	Weighted Average Remaining Contractual Life in Years	Aggregate Intrinsic Value	Number of Stock-based Awards Exercisable	Weighted Average Remaining Contractual Life in Years	Aggregate Intrinsic Value
$ —	75	1.8	$ 3,933	—	—	$ —
20.13	29	0.3	924	29	0.3	924
23.34	99	0.4	2,897	99	0.4	2,897
35.15	15	4.1	257	15	4.1	257
38.24	15	3.8	211	15	3.8	211
42.87	942	3.5	8,879	521	3.5	4,918
47.46	38	4.9	182	38	4.9	182
53.16	35	5.9	—	—	—	—
53.44	828	5.5	—	—	—	—
55.16	296	4.9	—	66	4.9	—
57.97	30	5.6	—	30	5.6	—
58.79	16	3.5	—	—	—	—
63.35	109	4.9	—	33	4.9	—
	2,527	4.3	$ 17,283	846	3.3	$ 9,389

The aggregate intrinsic value in the above tables represents the total pretax intrinsic value, based on the Company's stock price of $74.52 and $52.30 as of December 31, 2019 and 2018, respectively, which would have potentially been received by the stock-based award holders had all stock-based award holders exercised their stock-based award as of those dates. The total number of in-the-money stock-based awards exercisable as of December 31, 2019 and 2018 was 479,402 and 846,215, respectively.

The total pretax intrinsic value of options exercised during the year ended December 31, 2019 and 2018 was $19.3 million and $5.2 million, respectively, based on the average stock price of $65.04 and $55.58 during the years ended December 31, 2019 and 2018, respectively. The stock price as of December 31, 2019 and 2018 was $75.14 and $52.30, respectively.

NOTE 16 — POWER PURCHASE AGREEMENTS

Substantially all of the Company's electricity revenues are recognized pursuant to PPAs in the United States and in various foreign countries, including Kenya, Guatemala, Guadeloupe and Honduras. These PPAs generally provide for the payment of energy payments or both energy and capacity payments through their respective terms which expire in varying periods from 2022 to 2047. Generally, capacity payments are calculated based on the amount of time that the power plants are available to generate electricity. The energy payments are calculated based on the amount of electrical energy delivered at a designated delivery point. The price terms are customary in the industry and include, among others, a fixed price, SRAC (the incremental cost that the power purchaser avoids by not having to generate such electrical energy itself or purchase it from others), and a fixed price with an escalation clause that includes the value for environmental attributes, known as renewable energy credits. Certain of the PPAs provide for bonus payments in the event that the Company is able to exceed certain target levels and potential payments by the Company if it fails to meet minimum target levels. The Company has PPAs that give the power purchaser or its designee a right of first refusal or a right of first offer to acquire the geothermal power plants at fair market value as negotiated between the parties. The Company's subsidiaries in Guatemala sell power at an agreed upon price subject to terms of a "take or pay" PPA. During the fourth quarter of 2019, one of the Company's subsidiaries in Guatemala started selling power under the energy and capacity framework once the "take or pay" arrangement ended.

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

NOTE 17 — INTEREST EXPENSE, NET

The components of interest expense are as follows:

	Year Ended December 31,		
	2019	2018	2017
	(Dollars in thousands)		
Interest related to sale of tax benefits	$ 11,786	$ 11,284	$ 6,985
Interest expense	71,883	63,368	54,381
Less — amount capitalized	(3,285)	(3,728)	(7,224)
	$ 80,384	$ 70,924	$ 54,142

NOTE 18 — INCOME TAXES

U.S. and foreign components of income from continuing operations, before income taxes and equity in income (losses) of investees consisted of:

	Year Ended December 31,		
	2019	2018	2017
	(Dollars in thousands)		
U.S.	$ 14,187	$ 14,097	$ 13,680
Non-U.S. (foreign)	123,116	123,084	157,050
Total income from continuing operations, before income taxes and equity in losses	$ 137,303	$ 137,181	$ 170,730

The components of the provision (benefit) for income taxes, net are as follows:

	Year Ended December 31,		
	2019	2018	2017
	(Dollars in thousands)		
Current:			
Federal	$ —	$ 0	$ 43,935
State	172	381	43
Foreign	16,969	14,992	11,186
Total current income tax expense	$ 17,141	$ 15,373	$ 55,164
Deferred:			
Federal	(12,179)	(6,886)	(55,718)
State	4,671	(2,595)	(3,284)
Foreign	35,980	28,841	25,502
Total deferred tax provision (benefit)	28,472	19,360	(33,500)
Total Income tax provision	$ 45,613	$ 34,733	$ 21,664

Reconciliation of the U.S. federal statutory tax rate to the Company's effective income tax rate is as follows:

	Year Ended December 31,		
	2019	2018	2017
U.S. federal statutory tax rate	21.0%	21.0%	35.0%
Impact of federal tax reform	0.0	2.6	(12.4)
Transition tax inclusion	—	(5.7)	42.1
Foreign tax credits	(22.8)	(4.2)	(50.5)
Withholding tax	10.4	5.9	34.1
Valuation allowance - U.S.	(3.7)	(17.2)	(22.6)
State income tax, net of federal benefit	3.7	1.0	1.1
Uncertain tax positions	2.1	2.1	—
Effect of foreign income tax, net	9.7	5.6	(10.7)
Production tax credits	(5.0)	(3.1)	(1.2)
Subpart F income	0.5	0.5	1.7
Tax on global intangible low-tax income	16.9	18.6	—
Intra-entity transfers of assets other than inventory	0.3	(2.1)	—
Other, net	0.1	0.3	(3.9)
Effective tax rate	33.2%	25.3%	12.7%

The net deferred tax assets and liabilities consist of the following:

	December 31,	
	2019	2018
	(Dollars in thousands)	
Deferred tax assets (liabilities):		
Net foreign deferred taxes, primarily depreciation	$ (88,508)	$ (57,202)
Depreciation	(21,958)	(30,500)
Intangible drilling costs	(1,405)	7,370
Net operating loss carryforward - U.S.	45,307	65,020
Tax monetization transaction	(30,964)	(17,104)
Right-of-use assets	(3,715)	—
Lease liabilities	3,755	—
State and Investment tax credits	813	813
Production tax credits	100,524	90,913
Foreign tax credits	92,497	58,072
Withholding tax	(15,539)	(8,052)
Stock options amortization	1,409	1,440
Basis difference in partnership interest	(39,622)	(36,516)
Excess business interest	6,189	—
Accrued liabilities and other	1,013	624
	49,796	74,878
Less - valuation allowance	(17,412)	(22,441)
Total	$ 32,384	$ 52,437

The following table presents a reconciliation of the beginning and ending valuation allowance:

	2019	2018	2017
	(Dollars in thousands)		
Balance at beginning of the year	$ 22,441	$ 77,571	$ 116,234
Additions to valuation allowance	15,437	4,747	46,560
Release of valuation allowance	(20,466)	(59,877)	(85,223)
Balance at end of the year	$ 17,412	$ 22,441	$ 77,571

At December 31, 2019, the Company had U.S. federal net operating loss (“NOL”) carryforwards of approximately $132.7 million, of this amount, $127.9 million was generated before 2018 and expires between 2032 and 2037. The remaining $4.8 million was generated after 2017 and is available to be carried forward for an indefinite period.

At December 31, 2019, the Company had production tax credits (“PTCs") in the amount of $100.5 million. These PTCs are available for a 20-year period and expire between 2022 and 2039. At December 31, 2019, the Company had U.S. foreign tax credits (“FTCs”) in the amount of $92.5 million. These FTCs are available for a 10-year period and begin to expire in 2022.

At December 31, 2019, the Company had state NOL carryforwards of approximately $277.9 million, $275.5 million which expire between 2025 and 2039 and $2.4 million are available to be carried forward for an indefinite period. At December 31, 2019, the Company had state tax credits in the amount of $0.8 million. These state tax credits are available to be carried forward for an indefinite period.

The Company has recorded deferred tax assets for net operating losses, foreign tax credits, and production tax credits. Realization of the deferred tax assets and tax credits is dependent on generating sufficient taxable income in appropriate jurisdictions prior to expiration of the NOL carryforwards and tax credits. Based upon available evidence of the Company’s ability to generate additional taxable income in the future and historical losses in prior years, a valuation allowance in the amount of $17.4 million and $22.4 million is recorded against the U.S. deferred tax assets as of December

31, 2019 and 2018, respectively, as it is more likely than not that the deferred tax assets will not be realized. The overall decrease in the valuation allowance of $5.0 million is due to full utilization of foreign tax credits that generated the valuation allowance at December 31, 2018, which were offset by increased valuation allowance related to production tax credits. The Company is maintaining a valuation allowance of $17.4 million against a portion of the U.S. production tax credits and state NOLs that are expected to expire before they can be utilized in future periods.

On April 24, 2018, the Company acquired 100% of stock of USG for approximately $110 million. Under the acquisition method of accounting, the Company recorded a net deferred tax asset of $1.7 million comprised primarily of federal and state NOLs netted against deferred tax liabilities for partnership basis differences and fixed assets. The total amount of acquired federal and state NOLs, which are subject to limitations under Section 382, were $115.2 million and $49.9 million, respectively. A valuation allowance of $2.1 million has been recorded against such acquired state NOLs, as it is more likely than not that the deferred tax asset will not be realized.

On December 22, 2017, the U.S. government signed into law the Tax Act. The Tax Act made significant changes to the U.S. tax code, including, but not limited to, (1) reducing the U.S. federal corporate income tax rate from 35 percent to 21 percent; (2) the transition of U.S. international taxation from a worldwide tax system to a territorial system (GILTI, BEAT, Dividends Received Deduction); (3) one-time transition tax on undistributed earnings of foreign subsidiaries as of December 31, 2017; (4) eliminating the corporate alternative minimum tax; (5) creating a new limitation on deductible interest expense; and (6) changing rules related to uses and limitations of net operating loss carryforwards created in tax years beginning after December 31, 2017.

The FASB released guidance Staff Q&A, Topic 740, No. 5, that states a company can make an accounting policy election to either recognize deferred taxes related to GILTI or to provide for the GILTI tax expense in the year the tax is incurred as a period cost. The Company has elected to treat any GILTI inclusions as a period cost.

The following table presents the deferred taxes on the balance sheet as of the dates indicated:

	Year Ended December 31,		
	2019	2018	2017
	(Dollars in thousands)		
Non-current deferred tax assets	$ 129,510	$ 113,760	$ 57,337
Non-current deferred tax liabilities	(97,126)	(61,323)	(61,961)
Non-current deferred tax assets, net	32,384	52,437	(4,624)
Uncertain tax benefit offset [1]	(95)	(95)	(95)
	$ 32,289	$ 52,342	$ (4,719)

(1) The non-current deferred tax asset has been reduced by the uncertain tax benefit of $0.1 million in accordance with ASU 2013-11, Income Taxes.

At December 31, 2019, the Company is no longer indefinitely reinvested with respect to the earnings of its foreign subsidiaries due to forecasted changes in cash needs and the impact of U.S. tax reform. The Company has accrued withholding taxes that would be owed upon future distributions of such earnings, with the exception of a certain balance of earnings held in Israel. Accordingly, during 2019, the Company included a foreign income tax expense of $13.9 million related to foreign withholding taxes on future distributions of foreign earnings.

At December 31, 2018, the Company asserted indefinite reinvestment of undistributed earnings of foreign subsidiaries, other than OSL and as a result, did not record a DTL on the future tax impacts of their remittances.

During 2017, the Company changed its intention to reinvest certain undistributed earnings of Ormat Systems Ltd., a wholly owned subsidiary in Israel. In the prior year, the Company distributed $396.0 million, of which $300.0 million was received in December 2017 and the remaining $96.0 million was received in December 2018. The Company recorded the tax impact of the distribution received in 2018 as part of the 2017 financials, including the 15% Israeli withholding tax in the amount of $14.4 million and corresponding foreign tax credit tax benefit, net of valuation allowance.

Uncertain tax positions

The Company is subject to income taxes in the United States (federal and state) and numerous foreign jurisdictions. Significant judgment is required in evaluating the Company's tax positions and determining its provision for income taxes. During the ordinary course of business, there are many transactions and calculations for which the ultimate tax determination is uncertain. The Company establishes reserves for tax-related uncertainties based on estimates of whether, and the extent to which additional taxes will be due. These reserves are established when the Company believes that certain positions might be challenged despite evidence supporting the position. The Company adjusts these reserves in light of changing facts and circumstances, such as the outcome of tax audits. The provision for income taxes includes the impact of reserve positions and changes to reserves that are considered probable.

At December 31, 2019 and 2018, there are $14.6 million and $11.8 million of unrecognized tax benefits, respectively, that if recognized would reduce the effective tax rate . Interest and penalties assessed by taxing authorities on an underpayment of income taxes are included as a component of income tax provision in the consolidated statements of operations and comprehensive income.

A reconciliation of the Company's unrecognized tax benefits is as follows:

	Year Ended December 31,		
	2019	2018	2017
	(Dollars in thousands)		
Balance at beginning of year	$ 8,820	$ 6,357	$ 4,609
Additions based on tax positions taken in prior years	104	293	5
Additions based on tax positions taken in the current year	2,314	2,446	2,580
Reduction based on tax positions taken in prior years	(615)	(276)	(837)
Balance at end of year	$ 10,623	$ 8,820	$ 6,357

The Company and its U.S. subsidiaries file consolidated income tax returns for federal and state (where applicable) purposes. As of December 31, 2019, the Company has not been subject to U.S. federal or state income tax examinations.

The Company remains open to examination by the Internal Revenue Service for the years 2002-2019 and by local state jurisdictions for the years 2004-2019. These examinations may lead to ordinary course adjustments or proposed adjustments to the Company's taxes or the Company's net operating losses with respect to years under examination as well as subsequent periods.

The Company’s foreign subsidiaries remain open to examination by the local income tax authorities in the following countries for the years indicated:

Israel	2015 - 2019
Kenya	2013 - 2019
Guatemala	2015 - 2019
Honduras	2015 - 2019
Guadeloupe	2017 - 2019
New Zealand	2012 - 2019

Management believes that the liability for unrecognized tax benefits is adequate for all open tax years based on its assessment of many factors, including among others, past experience and interpretations of local income tax regulations. This assessment relies on estimates and assumptions and may involve a series of complex judgments about future events. As a result, it is possible that federal, state and foreign tax examinations will result in assessments in future periods. To the extent any such assessments occur, the Company will adjust its liability for unrecognized tax benefits. The Company is not able to reasonably estimate the amount of unrecognized tax benefits that will be reduced within the next twelve months.

Tax benefits in the United States

The U.S. government encourages production of electricity from geothermal resources through certain tax subsidies. On February 9, 2018 the Bipartisan Budget Act of 2018 was enacted extending the PTC and ITC in lieu of PTCs for geothermal projects that began construction before 2018. On December 20, 2019, the Tax Extenders Bill was enacted, further extending the PTC and ITC in lieu of PTCs. Therefore, geothermal projects that begin construction before 2021 and meet certain other "beginning of construction" rules qualify for PTCs for their first 10-years of operations; alternatively, the owner of the project may elect to claim the ITC in lieu of PTCs. In either case, under current tax rules for tax credits, any unused tax credit has a 1-year carry back and a 20-year carry forward.

If the Company claims the ITC, the Company's "tax base" in the plant that it can recover through bonus or accelerated depreciation (if elected) must be reduced by half of the ITC. If the Company claims the PTC, there is no reduction in the tax basis for depreciation. Whether the Company claims the PTC or the ITC in lieu of PTC, for assets acquired and placed in service after September 27, 2017, the Company is eligible to expense 100% of the cost of qualified property ("bonus depreciation"). In later years, the first-year bonus depreciation deduction phases down, as follows:

- 80% for property placed in service after Dec. 31, 2022 and before Jan. 1, 2024.
- 60% for property placed in service after Dec. 31, 2023 and before Jan. 1, 2025.
- 40% for property placed in service after Dec. 31, 2024 and before Jan. 1, 2026.
- 20% for property placed in service after Dec. 31, 2025 and before Jan. 1, 2027.

The Company could also elect in lieu of bonus deprecation to depreciate most of its "tax base" in the plant for tax purposes 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.

Income taxes related to foreign operations

Guatemala — The enacted tax rate is 25%. Orzunil, a wholly owned subsidiary, was granted a benefit under a law which promotes development of renewable power sources. The law allows Orzunil to reduce the investment made in its geothermal power plant from income tax payable, which currently reduces the effective tax rate to zero. Ortitlan, another wholly owned subsidiary, was granted a tax exemption for a period of ten years ending August 2017. Starting August 2017, Ortitlan pays income tax of 7% on its Electricity revenues.

Israel — The Company's operations in Israel through its wholly owned Israeli subsidiary, Ormat Systems Ltd. ("Ormat Systems"), are taxed at the regular corporate tax rate of 24% in 2017 and 23% in 2018 and thereafter. Ormat Systems received "Benefited Enterprise" status under Israel's Law for Encouragement of Capital Investments, 1959 (the "Investment Law"), with respect to two of its investment programs. In January 2011, new legislation amending the Investment Law was enacted. Under the new legislation, a uniform rate of corporate tax would apply to all qualified income of certain industrial companies, as opposed to the current law's incentives that are limited to income from a "Benefited Enterprise" during their benefits period. According to the amendment, the uniform tax rate applicable to the zone where the production facilities of Ormat Systems are located would be 16% in 2014 and thereafter. Ormat Systems decided to irrevocably comply with the new law starting in 2011. In the event of distribution of a cash dividend out of retained earnings which were tax exempt due to prior benefits, Ormat Systems would have to pay tax in respect of the amount distributed. Since the exemptions are contingent upon nondistribution of dividends and since upon liquidation the Company will have to pay a 25% tax on exempt income, Ormat Systems recorded deferred tax liability at the rate of 25% in respect of the tax exempt income in 2004-2008. In the event that Ormat Systems fails to comply with the program terms, the tax benefits may be canceled and it may be required to refund the amount of the benefits utilized, in whole or in part, with the addition of linkage differences and interest.

Kenya - The Company's operations in Kenya are taxed at the rate of 37.5%. On September 11, 2015, Kenya's Income Tax Act was amended pursuant to certain provisions of the recently adopted Finance Act, 2015. Among other matters, these amendments retain the enhanced investment deduction of 150% under Section 17B of the Income Tax Act, extend the period for deduction of tax losses from 5 years to 10 years under Sections 15(4) and 15(5) of the Income Tax Act, and amend the effective date from January 1, 2016 to January 1, 2015 under Sections 15(4) and 15(5) of the Income Tax Act.

Tax audit in Kenya

The Company received three letters from the Kenya Revenue Authority ("KRA") relating to certain findings in respect of its review of tax years 2013 to 2017 as described below:

The first Letter of Preliminary Findings was received in March 2019, which was followed by a Notice of Assessment during June 2019 in which the KRA demanded approximately $5.6 million from the Company, including interest and penalties in respect of two certain issues relating to its review of tax years 2014 to 2017. In July 2019, the Company responded to the KRA Notice of Assessment primarily objecting to one of the two issues raised in the assessment, consisting of approximately $4.4 million, and asked the KRA to vacate this issue as set forth in its tax assessment letter.

The Company received the second Letter of Preliminary Findings ("the Second Letter of Preliminary Findings") from the KRA in July 2019, which relates to findings from the KRA's audit review for tax years 2013 to 2017. In August 2019, the Company filed its response to the Second Letter of Preliminary Findings, contesting the KRA arguments and requesting that the KRA vacate all issues set forth in its Letter of Preliminary Findings. In December 2019, the KRA submitted its audit assessment letter in relation to the 2013 to 2017 tax years in which it demanded approximately $205 million from the Company, including interest and penalties in respect of the issues included in its Second Letter of Preliminary Findings. In January 2020, the Company responded to the KRA objecting to all the issues raised in the tax assessment for tax years 2013 to 2017 and asked the KRA to vacate all issues set forth in its tax assessment letter.

The Company received the third Letter of Preliminary Findings (the "Third Letter of Preliminary Findings") from the KRA in December 2019 relating to the same tax years in which the KRA set forth an additional demand for approximately $17 million, including interest and penalties, in relation to an additional audit finding which was not previously included in the KRA's assessments. In January 2020, the Company filed a formal objection to the Third Letter of Preliminary Findings, contesting the KRA's finding.

The Company is currently at different stages of discussions with the KRA on the matters included in the KRA letters of assessment and preliminary findings as described above and believes its tax positions for the issues raised during the audit period is more-likely-than-not sustainable based on technical merits under Kenyan tax law. As of December 31, 2019, the Company has not recorded any tax reserves related to these demands except for an immaterial amount included in the first Letter of Preliminary Findings.

Guadeloupe - The Company’s operations in Guadeloupe are taxed at a rate of 34.43% in 2017, a maximum rate of 33.3% in 2018, a maximum rate 31% in 2019, a rate of 28% in 2020, 26.5% in 2021 and 25% in 2022.

Honduras - The Company’s operations in Honduras are exempt from income taxes for the first ten years starting at the commercial operation date of the power plant.

NOTE 19 — BUSINESS SEGMENTS

In 2018, the Company started disclosing its energy storage and power load management business activity under the Energy Storage and Management Services segment as such operations met the reportable segment criteria of ASC 280, Segment Reporting. In 2019, under this business activity, the Company completed two BESS projects in New Jersey, which started generating revenues during that year, and is focused on increasing activity under this reporting segment. As such, the Company renamed its Other reportable segment to "Energy Storage and Management Services" ("ESMS"). This segment only included the Company's storage related activity starting in 2018 as disclosed above. As such, starting in 2018 the Company has three reporting segments: the Electricity segment, the Product segment and the Energy Storage and Management Services segment. These segments are managed and reported separately as each offers different products and serves different markets. The Electricity segment is engaged in the sale of electricity from the Company’s power plants pursuant to PPAs. The Product segment is engaged in the manufacture, including design and development, of turbines and power units for the supply of electrical energy and in the associated construction of power plants utilizing the power units manufactured by the Company to supply energy from geothermal fields and other alternative energy sources. The Energy Storage and Management Services segment is engaged in battery energy storage systems as a service and management of curtailable customer loads under contracts with U.S. retail energy providers and directly with large commercial and industrial customers.

Transfer prices between the operating segments were determined on current market values or cost plus markup of the seller's business segment.

Summarized financial information concerning the Company's reportable segments is shown in the following tables, including, as further described under Note 1 to the consolidated financial statements, the Company's disaggregated revenues from contracts with customers as required by ASC 606:

	Electricity	Product	ESMS	Consolidated
	(Dollars in thousands)			
Year Ended December 31, 2019:				
Revenues from external customers:				
United States [1]	$ 333,797	$ 30,562	$ 13,597	$ 377,956
Foreign [2]	206,536	160,447	1,105	368,088
Net revenues from external customers	540,333	191,009	14,702	746,044
Intersegment revenues	—	84,614	—	84,614
Depreciation and amortization expense	138,426	5,308	5,027	148,761
Operating income (loss)	177,192	23,180	(6,576)	193,796
Segment assets at period end [3] [*]	3,044,909	126,018	79,567	3,250,494
Expenditures for long-lived assets	259,898	9,156	10,932	279,986
* Including unconsolidated investments	81,140	—	—	81,140
Year Ended December 31, 2018:				
Revenues from external customers:				
United States [1]	305,962	14,999	7,645	328,606
Foreign [2]	203,917	186,744	—	390,661
Net revenues from external customers	$ 509,879	$ 201,743	$ 7,645	$ 719,267
Intersegment revenues	—	48,817	—	48,817
Depreciation and amortization expense	126,181	4,311	1,741	132,233
Operating income (loss)	155,546	38,083	(8,519)	185,110
Segment assets at period end [3] [*]	2,896,938	156,942	67,470	3,121,350
Expenditures for long-lived assets	219,803	9,993	28,725	258,521
* Including unconsolidated investments	71,983	—	—	71,983
Year Ended December 31, 2017:				
Revenues from external customers	$ 465,593	$ 224,483	$ 2,736	$ 692,812
Intersegment revenues	—	109,040	—	109,040
Depreciation and amortization expense	109,928	3,470	1,748	115,146
Operating income (loss)	157,613	50,543	(3,138)	205,018
Segment assets at period end [3] [*]	2,457,514	115,713	50,637	2,623,864
Expenditures for long-lived assets	252,581	6,653	—	259,234
* Including unconsolidated investments	34,084	—	—	34,084

(1) Electricity segment revenues in the United States are all accounted under lease accounting, except for $61.3 million and $26.9 million for the years December 31, 2019 and 2018 that are accounted under ASC 606 starting in 2018. Product and Energy Storage and Management Services segment revenues in the United States are accounted under ASC 606, as further described under Note 1 to the consolidated financial statements.

(2) Electricity segment revenues in foreign countries are all accounted under lease accounting. Product and Energy Storage and Management Services segment revenues in foreign countries are accounted under ASC 606 as further described under Note 1 to the consolidated financial statements.

(3) Electricity segment assets include goodwill in the amount of $20.1 million, $20.0 million and $7.6 as of December 31, 2019, 2018 and 2017, respectively. No goodwill is included in the Product and Energy Storage and Management Services segment assets as of December 31, 2019 and 2018. Energy Storage and Management Services segment assets as December 31, 2017 include goodwill in the amount of $13.5 million. For further information on goodwill, see Note 9 – Intangible assets and goodwill to the consolidated financial statements.

Reconciling information between reportable segments and the Company's consolidated totals is shown in the following table:

	Year Ended December 31,		
	2019	2018	2017
	(Dollars in thousands)		
Revenues:			
Total segment revenues	$ 746,044	$ 719,267	$ 692,812
Intersegment revenues	84,614	48,817	109,040
Elimination of intersegment revenues	(84,614)	(48,817)	(109,040)
Total consolidated revenues	$ 746,044	$ 719,267	$ 692,812
Operating income:			
Operating income	$ 193,796	$ 185,110	$ 205,018
Interest income	1,515	974	988
Interest expense, net	(80,384)	(70,924)	(54,142)
Derivatives and foreign currency transaction gains (losses)	624	(4,761)	2,654
Income attributable to sale of tax benefits	20,872	19,003	17,878
Other non-operating income (expense), net	880	7,779	(1,666)
Total consolidated income before income taxes and equity in earnings of investees	$ 137,303	$ 137,181	$ 170,730

The Company sells electricity, products and energy storage and other related services mainly to the geographical areas set forth below based on the location of the customer. The following tables present certain data by geographic area:

	Year Ended December 31,		
	2019	2018	2017
	(Dollars in thousands)		
Revenues from external customers attributable to: [1]			
United States	$ 377,956	$ 328,606	$ 301,132
Indonesia	—	4,379	28,968
Kenya	121,661	119,094	110,243
Turkey	88,938	168,699	125,166
Chile	25,540	980	8,895
Guatemala	28,624	27,975	27,991
New Zealand	31,222	10,451	33,395
Honduras	34,446	34,355	10,151
Other foreign countries	37,657	24,728	46,871
Consolidated total	$ 746,044	$ 719,267	$ 692,812

[1] Revenues as reported in the geographic area in which they originate.

	Year Ended December 31,		
	2019	2018	2017
	(Dollars in thousands)		
Long-lived assets (primarily power plants and related assets) located in:			
United States	$ 1,870,335	$ 1,696,439	$ 1,510,986
Kenya	284,526	301,956	340,970
Other foreign countries	224,676	222,872	281,333
Consolidated total	$ 2,379,537	$ 2,221,267	$ 2,133,289

The following table presents revenues from major customers:

	Year Ended December 31,					
	2019		2018		2017	
	Revenues	%	Revenues	%	Revenues	%
	(Dollars in thousands)		(Dollars in thousands)		(Dollars in thousands)	
Southern California Public Power [1]	$ 133,725	17.9	$ 109,208	15.2	$ 70,100	10.1
Sierra Pacific Power Company and Nevada Power Company [1][2]	125,486	16.8	116,149	16.1	125,424	18.1
KPLC [1]	121,661	16.3	119,094	16.6	110,243	15.9

[1]Revenues reported in Electricity segment.
[2]Subsidiaries of NV Energy, Inc.

NOTE 20 — TRANSACTIONS WITH RELATED ENTITIES

There were no transactions between the Company and related entities, other than those disclosed elsewhere in these financial statements.

NOTE 21 — EMPLOYEE BENEFIT PLAN

401*(k) Plan*

The Company has a 401(k) Plan (the "Plan") for the benefit of its U.S. employees. Employees of the Company and its U.S. subsidiaries who have completed 60 days of employment are eligible to participate in the Plan. Contributions are made by employees through pre- and post-tax deductions up to 60% of their annual salary. In 2019, 2018 and 2017, the Company matched employee contributions, after completion of one year of service, up to a maximum of 4%, 4% and 3% of the employee's annual salary, respectively. The Company's contributions to the Plan were $1.6 million, $1.6 million and $1.4 million for the years ended December 31, 2019, 2018 and 2017, respectively.

Severance plan

The Company, through Ormat Systems, provides limited non-pension benefits to all current employees in Israel who are entitled to benefits in the event of termination or retirement in accordance with the Israeli Government sponsored programs. These plans generally obligate the Company to pay one month's salary per year of service to employees in the event of involuntary termination. There is no limit on the number of years of service in the calculation of the benefit obligation. The liabilities for these plans are recorded at each balance sheet date by determining the undiscounted obligation as if it were payable at that point in time. Such liabilities have been presented in the consolidated balance sheets as "liabilities for severance pay". The Company has an obligation to partially fund the liabilities through regular deposits in pension funds and severance pay funds. The amounts funded amounted to $10.8 million and $10.6 million at December 31, 2019 and 2018, respectively, and have been presented in the consolidated balance sheets as part of "deposits and other". The severance pay liability covered by the pension funds is not reflected in the financial statements as the severance pay risks have been irrevocably transferred to the pension funds. Under the Israeli severance pay law, restricted funds may not be withdrawn or pledged until the respective severance pay obligations have been met. As allowed under the program, earnings from the investment are used to offset severance pay costs. Severance pay expenses for the years ended December 31, 2019, 2018 and 2017 were $3.5 million, $3.0 million and $3.2 million, respectively, which are net of income (including loss) amounting to $1.0 million, $(1.1) million, and $1.8 million, respectively, generated from the regular deposits and amounts accrued in severance funds.

The Company expects to pay the following future benefits to its employees upon their reaching normal retirement age:

	(Dollars in thousands)
Year ending December 31:	
2020	$ 4,780
2021	1,434
2022	1,768
2023	89
2024	500
2025-2043	11,232
Total	**$ 19,803**

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

NOTE 22 — COMMITMENTS AND CONTINGENCIES

Geothermal resources

The Company, through its project subsidiaries in the United States, controls certain rights to geothermal fluids through certain leases with the BLM or through private leases. Royalties on the utilization of the geothermal resources are computed and paid to the lessors as defined in the respective agreements. Royalty expense under the geothermal resource agreements were $21.7 million, $21.6 million and $19.4 million for the years ended December 31, 2019, 2018 and 2017, respectively.

Letters of credit

In the ordinary course of business with customers, vendors, and lenders, the Company is contingently liable for performance under letters of credit totaling $213.8 million at December 31, 2019. Management does not expect any material losses to result from these letters of credit because performance is not expected to be required, and, therefore, is of the opinion that the fair value of these instruments is zero.

Purchase commitments

The Company purchases raw materials for inventories, construction-in-process and services from a variety of vendors. During the normal course of business, in order to manage manufacturing lead times and help assure adequate supply, the Company enters into agreements with contract manufacturers and suppliers that either allow them to procure goods and services based upon specifications defined by the Company, or that establish parameters defining the Company's requirements.

At December 31, 2019, total obligations related to such supplier agreements were approximately $185.0 million (out of which approximately $59.5 million relate to construction-in-process). All such obligations are payable in 2019.

Grants and royalties

The Company, through Ormat Systems, had historically, through December 31, 2003, requested and received grants for research and development from the Office of the Chief Scientist of the Israeli Government. Ormat Systems is required to pay royalties to the Israeli Government at a rate of 3.5% to 5.0% of the revenues derived from products and services developed using these grants. No royalties were paid for the years ended December 31, 2019, 2018 and 2017. The Company is not liable for royalties if the Company does not sell such products and services. Such royalties are capped at the amount of the grants received plus interest at LIBOR. The cap at December 31, 2019 and 2018, amounted to $2.1 million and $2.0 million, respectively, of which approximately $1.1 million and $1.0 million, respectively, represents interest based on the LIBOR rate, as defined above.

Lease commitments

The Company's lease commitments are detailed under Note 23, Leases to the consolidated financial statements.

Contingencies

- On May 21, 2018, a motion to certify a class action was filed in Tel Aviv District Court against Ormat Technologies, Inc. and 11 officers and directors. The alleged class is defined as "All persons who purchased Ormat shares on the Tel Aviv Stock Exchange between August 3, 2017 and May 13, 2018". The motion alleges that the Company violated Sections 31(a)(1) and 38C of the Israeli Securities Law because it allegedly: (1) misled investors by stating in its financial statements that it maintains effective internal controls over its accounting policies and procedures, however the Company's internal controls had material weaknesses which led to erroneous accounting in its 2017 unaudited quarterly reports that had to be restated, including adjustments to the Company's net income and shareholders' equity; and (2) failed to issue an immediate report in Israel until May 16, 2018, analogous to the report that was released in the United States on May 11, 2018 stating, inter alia, that the errors in its financial reports affected its balance sheet and would be remedied in its 2017 annual report. The Company filed an agreed motion to the Tel Aviv District Court to stay the proceedings in Israel until a final decision in the U.S. case (Mac Costas) is adjudicated.

- On June 11, 2018, a putative class action was filed by Mac Costas on behalf of alleged shareholders that purchased or acquired the Company's ordinary shares between August 8, 2017 and May 15, 2018 was commenced in the U.S. District Court for the District of Nevada against the Company and its Chief Executive Officer and Chief Financial Officer, which was subsequently amended by a consolidated complaint filed by lead plaintiff Phoenix Insurance in May 13, 2019. The complaint asserts claim against all defendants pursuant to Section 10(b) of the Exchange Act, as amended, and Rule 10b-5 thereunder and against its officers pursuant to Section 20(a) of the Exchange Act. The complaint alleges that the Company's Form 10-K for the years ended December 31, 2016 and 2017, and Form 10-Qs for each of the quarters in the nine months ended September 30, 2017 contained material misstatements or omissions, among other things, with respect to the Company's tax provisions and the effectiveness of its internal control over financial reporting, and that, as a result of such alleged misstatements and omissions, the plaintiffs suffered damages. On December 6, 2019 the Company's motion to dismiss was denied by the court. The Company believes that it has valid defenses under law and intends to defend itself vigorously.

- On September 11, 2018, the Klein derivative action ("Klein Action") was filed against the Company, its board and its CEO and CFO in the U.S. District Court for the District of Nevada, and on October 22, 2018, the Matthew derivative action ("Matthew Action") was filed against the company, certain named present and former board members (Barniv, Beck, Boehm, Clark, Falk, Freeland, Granot, Joyal, Nishigori, Sharir, Stern and Wong) in the U.S. District Court, District of Nevada. The Klein complaint asserts four derivative causes of action generally arising from Ormat's restatement of its financial statements: (i) the individual defendants allegedly breached their fiduciary duties by allowing the company to improperly report its financials; (ii) the individual defendants allegedly were unjustly enriched by being compensated while breaching their fiduciary duties; (iii) the individual defendants allegedly committed corporate waste in paying officers and directors and by incurring legal costs and potential liability; and (iv) the director defendants allegedly breached Section 14(a) of the Exchange Act in connection with the issuance of 2018 proxy. The Matthew complaint similarly alleges derivatively a breach of fiduciary duties, abuse of control, gross mismanagement, and corporate waste by the named directors. On January 24, 2019, the Nevada Court entered an order consolidating the Klein Action and Matthew Action, and staying all deadlines and hearings in the consolidated action pending entry of an order on the motion to dismiss in the Mac Costas putative class action. Pursuant to the court's denial of the motion to dismiss in the Mac Costas putative class action, the parties have stipulated a delay in the scheduling and meet to enable out of court discussions of a possible resolution.

- Following the announcement of the Company's acquisition of USG, a number of putative shareholder class action complaints were initially filed on behalf of USG shareholders between March 8, 2018 and March 30, 2018 against USG and the individual members of the USG board of directors. All of the purported class action suits filed in Federal Court in Idaho have been voluntarily dismissed. The single remaining class action complaint is a purported class action filed in the Delaware Chancery Court, entitled Riche v. Pappas, et al., Case No. 2018-0177 (Del. Ch., Mar. 12, 2018). An amended complaint was filed on May 24, 2018 under seal, under a confidentiality agreement that was executed by plaintiff. The amended Riche complaint alleges state law claims for breach of fiduciary duty

against former USG directors and seeks post-closing damages. The Company believes that it has valid defenses under law and intends to defend itself vigorously.

- On August 5, 2016, George Douvris, Stephanie Douvris, Michael Hale, Cheryl Cacocci, Hillary E. Wilt and Christina Bryan, acting for themselves and on behalf of all other similarly situated residents of the lower Puna District, filed a complaint in the Third Circuit Court for the State of Hawaii seeking certification of a class action for preliminary and permanent injunctive relief, consequential and punitive damages, attorney's fees and statutory interest against PGV and other presently unknown defendants. HELCO and other parties were later joined as co-defendants. The Parties have reached an amicable settlement in an immaterial amount which, on April 4, 2019, was recorded by the Court, and the claim dismissed.

- On March 29, 2016, a former local sales representative in Chile, Aquavant, S.A., filed a claim on the basis of unjust enrichment against Ormat's subsidiaries in the 27th Civil Court of Santiago, Chile. The claim requests that the court order Ormat to pay Aquavant $4.6 million in connection with its activities in Chile, including the EPC contract for the Cerro Pabellon project and various geothermal concessions, plus 3.75% of Ormat geothermal products sales in Chile over the next 10 years. Pursuant to various motions submitted by the defendants and the plaintiffs to various courts, including the Court of Appeals, the case was removed from the original court and then refiled before the 11th Civil Court of Santiago. The Civil Court has heard oral testimonies and the "factual" stage of the proceedings are completed. The Company believes that it has valid defenses under law and intends to defend itself vigorously.

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

NOTE 23 — LEASES

The Company is a lessee in operating lease transactions primarily consisting of land leases for its exploration and development activities. Additionally, the Company was a lessee under an operating lease in relation to the Puna power plant transaction which was terminated in December 2019 as further described under Note 12 to the consolidated financial statements. The Company is a lessee in finance lease transactions primarily consisting of fleet vehicles and office rentals. The Company is a Lessor in PPAs that are accounted under lease accounting, as further described under Note 1 to the consolidated financial statements under Revenues and cost of revenues.

A. Leases in which the Company is a lessee

The table below presents the effects on the amounts relating to total lease cost:

	Year Ended December 31, 2019
	(Dollars in thousands)
Lease cost	
Finance lease cost:	
Amortization of right-of-use assets	$ 3,273
Interest on lease liabilities	1,330
Operating lease cost	8,057
Variable lease cost	1,647
Short-term lease cost	—
Total lease cost	$ 14,307
Other information	
Cash paid for amounts included in the measurement of lease liabilities:	
Operating cash flows for finance leases	$ 1,330
Operating cash flows for operating leases	9,004
Financing cash flows for finance leases	3,164
Right-of-use assets obtained in exchange for new finance lease liabilities	5,262
Right-of-use assets obtained in exchange for new operating lease liabilities	6,364

Additional information as of December 31, 2019:	December 31, 2019
Weighted-average remaining lease term — finance leases (in years)	4.0
Weighted-average remaining lease term — operating leases (in years)	7.3
Weighted-average discount rate (in percentage)	5 %

Future minimum lease payments under non-cancellable leases as of December 31, 2019 were as follows:

	Operating Leases	Finance Leases
	(Dollars in thousands)	
Year ending December 31,		
2020	$ 2,742	$ 4,251
2021	2,701	3,948
2022	2,079	3,873
2023	1,524	2,758
2024	1,275	906
Thereafter	10,635	4,118
Total future minimum lease payments	20,956	19,854
Less imputed interest	4,205	5,577
Total	$ 16,751	$ 14,277

Future minimum lease payments under non-cancellable leases as of December 31, 2018, under ASC 840, Leases were as follows:

	(Dollars in thousands)
Year ending December 31,	
2019	$ 10,889
2020	7,515
2021	5,758
2022	4,415
2023	2,910
Thereafter	9,292
Total	$ 40,779

B. Leases in which the Company is a lessor

The table below presents the lease income recognized for lessors:

	Year Ended December 31, 2019
	(Dollars in thousands)
Lease income relating to lease payments of operating leases	$ 479,059
Lease income relating to variable lease payments not included in the measurement of the lease	—
Total	$ 479,059

NOTE 24 — QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

	Three Months Ended							
	Mar. 31, 2018	June 30, 2018	Sept. 30, 2018	Dec. 31, 2018	Mar. 31, 2019	June 30, 2019	Sept. 30, 2019	Dec. 31, 2019
	(Dollars in thousands, except per share amounts)							
Revenues:								
Electricity	$ 132,489	$ 122,179	$ 116,891	$ 138,320	$ 142,908	$ 129,079	$ 123,978	$ 144,368
Product	48,672	54,915	48,439	49,717	52,128	52,030	43,037	43,814
Energy storage and management services	2,862	1,205	1,150	2,428	4,002	2,956	3,484	4,260
Total revenues	184,023	178,299	166,480	190,465	199,038	184,065	170,499	192,442
Cost of revenues:								
Electricity	73,482	81,236	79,845	63,692	77,543	73,775	80,124	81,393
Product	33,726	37,573	35,669	33,729	42,106	41,316	31,073	31,479
Energy storage and management services	3,443	2,028	2,174	2,235	5,210	3,827	3,807	5,068
Total cost of revenues	110,651	120,837	117,688	99,656	124,859	118,918	115,004	117,940
Gross profit	73,372	57,462	48,792	90,809	74,179	65,147	55,495	74,502
Operating expenses:								
Research and development expenses	1,108	1,251	706	1,118	900	810	1,062	1,875
Selling and marketing expenses	3,699	3,712	8,578	3,813	3,865	3,276	3,783	4,123
General and administrative expenses	13,849	15,866	13,606	4,429	15,689	14,181	11,931	14,032
Impairment charge	—	—	—	13,464	—	—	—	—
Write-off of unsuccessful exploration activities	123	—	—	3	—	—	—	—
Operating income	54,593	36,633	25,902	67,982	53,725	46,880	38,719	54,472
Other income (expense):								
Interest income	113	189	214	458	293	420	482	320
Interest expense, net	(14,344)	(15,846)	(18,700)	(22,034)	(21,223)	(21,517)	(20,076)	(17,568)
Derivatives and foreign currency transaction gains (losses)	(1,599)	(529)	(383)	(2,250)	472	19	205	(72)
Income attributable to sale of tax benefits	7,361	3,556	4,066	4,020	7,764	4,637	4,056	4,415
Other non-operating income (expense), net	(20)	7,373	309	117	91	1,027	244	(482)
Income from operations before income tax and equity in earnings (losses) of investees	46,104	31,376	11,408	48,293	41,122	31,466	23,630	41,085
Income tax (provision)	26,942	(29,105)	(1,184)	(31,386)	(14,039)	3,529	(9,626)	(25,477)
Equity in earnings (losses) of investees, net	1,210	388	(117)	6,182	1,047	1,202	1,085	(1,481)
Net income	74,256	2,659	10,107	23,089	28,130	36,197	15,089	14,127
Net loss (income) attributable to noncontrolling interest	(4,748)	(3,002)	474	(4,869)	(2,184)	(2,259)	516	(1,521)
Net income (loss) attributable to the Company's stockholders	$ 69,508	$ (343)	$ 10,581	$ 18,220	$ 25,946	$ 33,938	$ 15,605	$ 12,606
Earnings (loss) per share attributable to the Company's stockholders								
Basic:								
Net income	$ 1.37	$ (0.01)	$ 0.21	$ 0.36	$ 0.51	$ 0.67	$ 0.31	$ 0.25
Diluted:								
Net income	$ 1.36	$ (0.01)	$ 0.21	$ 0.36	$ 0.51	$ 0.66	$ 0.30	$ 0.24
Weighted average number of shares used in computation of earnings per share attributable to the Company's stockholders:								
Basic	50,614	50,623	50,645	50,691	50,709	50,800	50,933	51,017
Diluted	51,051	50,958	50,963	50,936	51,012	51,094	51,334	51,511

NOTE 25 — SUBSEQUENT EVENTS

Cash dividend

On February 25, 2020, the Company's Board of Directors declared, approved and authorized payment of a quarterly dividend of $5.6 million ($0.11 per share) to all holders of the Company's issued and outstanding shares of common stock on March 12, 2020, payable on March 26, 2020.

Energy storage assets portfolio purchase transaction

On February 28, 2020, the Company entered into definitive agreements (the "Purchase Agreements") to acquire a portfolio of energy storage assets in California from a third party (the "Seller"). The acquisition includes one operating energy storage asset and one advanced development energy storage project, both partly contracted with South California Edison. The transaction is contingent upon specific conditions related to the projects and the transaction as well as other customary closing conditions. Under the terms of the Purchase Agreements, the Company will pay up to approximately $65 million in total consideration of which $51 million will be paid at closing, which is expected during the second quarter of 2020, and the rest will be paid upon the Seller meeting certain conditions as well as an earn out. The Company is currently evaluating the accounting impact of this transaction on its 2020 consolidated financial statements.

ITEM 9. *CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE*

None.

ITEM 9A. *CONTROLS AND PROCEDURES*

Disclosure Controls and Procedures

Evaluation of disclosure controls and procedure. Our management, including our Chief Executive Officer and Chief Financial Officer, have conducted the evaluation of our disclosure controls and procedures (as such term is defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) required by Rules 13a-15(b) or 15d-15(b) under the Exchange Act, as amended. Based on that evaluation, our management, including our Chief Executive Officer and Chief Financial Officer, concluded that our disclosure controls and procedures were not effective as of December 31, 2019 as a result of a material weakness in our internal control over financial reporting that existed at December 31, 2017 and has not been remediated by the end of the period covered by this Annual Report on Form 10-K.

Management's Report on Internal Control over Financial Reporting

Our management, including our Chief Executive Officer and Chief Financial Officer, is responsible for establishing and maintaining adequate internal control over financial reporting as described in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934, as amended, or the Exchange Act. Internal control over financial reporting is defined as a process designed by, or under the supervision of, the issuer's principal executive and principal financial officers, or persons performing similar functions, and effected by the issuer's board of directors, management and other personnel, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles and includes those policies and procedures that: (1) pertain to the maintenance of records that in reasonable detail accurately and fairly reflect the transactions and dispositions of the assets of the issuer, (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the issuer are being made only in accordance with authorizations of management and directors of the issuer and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of the issuer's assets that could have a material effect on the financial statements.

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

Evaluation of effectiveness of internal control over financial reporting. Our management, under the supervision and participation of our Chief Executive Officer and our Chief Financial Officer, has conducted an evaluation of the effectiveness of our internal control over financial reporting as of December 31, 2019 using criteria established in Internal Control - Integrated Framework (2013) issued by the COSO and, based on this evaluation, concluded that our internal control over financial reporting was not effective as of December 31, 2019 as a result of the material weakness in our internal control over financial reporting discussed below. A material weakness is a deficiency, or a combination of deficiencies, in internal control over financial reporting, such that there is a reasonable possibility that a material misstatement of our annual or interim financial statements will not be prevented or detected on a timely basis.

Material weakness. In connection with the change in our repatriation strategy and the related release of the US income tax valuation allowance in the second quarter of 2017, we did not perform an effective risk assessment related to our internal controls over the accounting for income taxes. As a result, we identified a deficiency in the design of our internal control over financial reporting related to our accounting for income taxes, which resulted in the restatements of our unaudited condensed consolidated financial statements for the three and six months ended June 30, 2017, the three and nine months ended September 30, 2017, and the restatement of our consolidated financial statements for the year ended December 31, 2017. Our management has concluded that this deficiency constitutes a material weakness in our internal control over financial reporting.

The effectiveness of the Company's internal control over financial reporting as of December 31, 2019 has been audited by Kesselman & Kesselman, Certified Public Accountants (Isr.), a member firm of PricewaterhouseCoopers International Limited, an independent registered public accounting firm, as stated in their report which appears in this Annual Report on Form 10-K.

Remediation Plan

Our management, with the oversight of the Audit Committee of the Board of Directors, has continued the process of remediating the material weakness. In connection with the remediation process, we have:

- performed an enhanced risk assessment related to our internal controls over the accounting for income taxes;
- recruited additional tax personnel throughout the year, including a VP of Tax in January 2019 and a Director of Tax in September 2019;
- engaged an external tax and accounting firm to prepare and review our annual and quarterly income tax provision;
- implemented specific control procedures for the review, analysis and reporting of our income tax accounts, including control procedures of projections that support the deferred tax assets and liabilities;
- strengthened our income tax controls with improved documentation, communication and oversight.

We have made substantial progress in developing and implementing our remediation plan, as we are adding to and improving our internal processes. The remaining tasks of our remediation plan is the hiring of additional personnel, implement automation of the key elements of the tax provision and modify controls as applicable in respect of such tasks in order to reduce the risk of material misstatement. The material weakness will not be considered remediated until those controls operate for a sufficient period of time and management has concluded, through testing, that those controls are operating effectively.

Changes in Internal Control over Financial Reporting

There were no changes in our internal control over financial reporting in the fourth quarter of 2019 that have materially affected or are reasonably likely to materially affect our internal control over financial reporting.

ITEM 9B. *OTHER INFORMATION*

None.

PART III

ITEM 10. *DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE*

Information required by this Item and not set forth below is incorporated herein by reference to our definitive proxy statement for the 2020 annual meeting.

The following table sets forth the name, age and positions of our directors, executive officers and persons who are executive officers of certain of our subsidiaries who perform policy making functions for us:

Name	Age	Position
Todd C. Freeland	53	Chairman of the Board of Directors and Independent Director
Byron G. Wong	68	Independent Director
Dan Falk	75	Independent Director
Stanley B. Stern	62	Independent Director
Yuichi Nishigori	63	Independent Director
David Granot	72	Independent Director
Ravit Barniv	56	Independent Director
Stan H. Koyanagi	59	Independent Director
Dafna Sharir	51	Independent Director
Isaac Angel	63	CEO*
Doron Blachar	52	President and CFO*
Zvi Krieger	64	Executive Vice President—Electricity Segment*
Shlomi Argas	55	Executive Vice President—Product Segment and Operations*
Bob Sullivan	57	Executive Vice President - Business Development Sales & Marketing

* Performs the functions described in the table, but is employed by Ormat Systems

Audit Committee

Information required by this Item and not set forth below is incorporated herein by reference to our definitive proxy statement for the 2020 annual meeting.

ITEM 11. *EXECUTIVE COMPENSATION*

Information required by this item and not set forth below is incorporated herein by reference to our definitive proxy statement for the 2020 annual meeting.

ITEM 12. *SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS*

Information required by this item and not set forth below is incorporated herein by reference to our definitive proxy statement for the 2020 annual meeting.

ITEM 13. *CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE*

Information required by this item and not set forth below is incorporated herein by reference to our definitive proxy statement for the 2020 annual meeting.

ITEM 14. *PRINCIPAL ACCOUNTANT FEES AND SERVICES*

Information required by this item is incorporated herein by reference to our definitive proxy statement for the 2020 annual meeting.

PART IV

ITEM 15. *EXHIBITS, FINANCIAL STATEMENT SCHEDULES*

(a) *(1) List of Financial Statements*

See Index to Financial Statements in Part II, Item 8 of this annual report.

(2) List of Financial Statement Schedules

All applicable schedule information is included in our Financial Statements in Part II, Item 8 of this annual report.

(b) Exhibit Index. We hereby file, as exhibits to this Annual Report, those exhibits listed on the Exhibit Index immediately following the signature page hereto.

Exhibit No.	Document

(C) EXHIBIT INDEX

2.1	Agreement and Plan of Merger, dated January 24, 2018, by and among Ormat Nevada Inc., OGP Holding Corp. and U.S. Geothermal Inc., incorporated by reference to Exhibit 2.1 to Ormat Technologies, Inc.'s Form 10-K filed with the Securities and Exchange Commission on March 16, 2018.
3.1	Fourth Amended and Restated Certificate of Incorporation, incorporated by reference to Exhibit 3.1 to Ormat Technologies, Inc.'s Current Report on Form 8-K filed with the Securities and Exchange Commission on November 12, 2019.
3.2	Fifth Amended and Restated By-laws, incorporated by reference to Exhibit 3.3 to Ormat Technologies, Inc.'s Current Report on Form 8-K filed with the Securities and Exchange Commission on November 12, 2019.
3.3	Amended and Restated Limited Liability Company Agreement of ORPD LLC, dated April 30, 2015, by and among Ormat Nevada Inc., Northleaf Geothermal Holdings LLC, and ORPD Holding LLC incorporated by reference to Exhibit 3.5 to Ormat Technologies, Inc.'s Quarterly Report on Form 10-Q filed with the Securities and Exchange Commission on May 7, 2015.
4.1	Form of Common Share Stock Certificate, incorporated by reference to Exhibit 4.1 to Ormat Technologies, Inc.'s Registration Statement on Form S-1 (File No. 333-117527) filed with the Securities and Exchange Commission on July 21, 2004.
4.2	Form of Preferred Share Stock Certificate, incorporated by reference to Exhibit 4.2 to Ormat Technologies, Inc.'s Registration Statement on Form S-1 (File No. 333-117527) filed with the Securities and Exchange Commission on July 21, 2004.
4.4	Indenture for Subordinated Debt Securities, dated as of January 16, 2006, between Ormat Technologies, Inc. and Union Bank of California, incorporated by reference to Exhibit 4.3 to Ormat Technologies, Inc.'s Registration Statement Amendment No. 1 on Form S-3 (File No. 333-131064) filed with the Securities and Exchange Commission on January 6, 2006.
4.5	Indenture of Trust and Security Agreement, dated September 23, 2011, among OFC 2 LLC, ORNI 15 LLC, ORNI 39 LLC, ORNI 42 LLC, HSS II, LLC, and Wilmington Trust Company, as Trustee and Depository, incorporated by reference to Exhibit 4.8 to Ormat Technologies, Inc.'s Quarterly Report on Form 10-Q filed with the Securities and Exchange Commission on November 4, 2011.
4.6+	Description of Securities Registered under Section 12 of the Securities Exchange Act of 1934

10.1.1 Agreement for Purchase of Membership Interests in ORPD LLC, dated as of February 5, 2015, by and between Ormat Nevada Inc. and Northleaf Geothermal Holdings LLC is incorporated by reference to Exhibit 3.5 to Ormat Technologies, Inc.'s Quarterly Report on Form 10-Q filed with the Securities and Exchange Commission on May 7, 2015.

10.1.2 Agreement for Purchase of Membership Interests in ORNI 37 LLC, dated as of November 22, 2016, by and between Northleaf Geothermal Holdings LLC and Ormat Nevada Inc., incorporated by reference to Exhibit 10.1.13 to Ormat Technologies, Inc.'s Form 10-K filed with the Securities and Exchange Commission on March 1, 2017.

10.1.3 Amended and Restated Limited Liability Company Agreement of Opal Geo LLC, dated as of December 16, 2016, by and between OrLeaf LLC and JPM Capital Corporation, incorporated by reference to Exhibit 10.1.14 to Ormat Technologies, Inc.'s Form 10-K filed with the Securities and Exchange Commission on March 1, 2017.

10.1.4 Equity Contribution Agreement, dated as of December 16, 2016, by and among JPM Capital Corporation, Ormat Nevada Inc. and OrLeaf LLC, incorporated by reference to Exhibit 10.1.15 to Ormat Technologies, Inc.'s Form 10-K filed with the Securities and Exchange Commission on March 1, 2017.

10.2.1 Power Purchase Contract dated, April 16, 1985, between Southern California Edison Company and Second Imperial Geothermal Company, incorporated by reference to Exhibit 10.3.7 to Ormat Technologies, Inc.'s Registration Statement Amendment No. 1 on Form S-1/A (File No. 333-117527) filed with the Securities and Exchange Commission on September 28, 2004.

10.2.2 Amendment No. 1, dated as of October 23, 1987, between Southern California Edison Company and Second Imperial Geothermal Company, incorporated by reference to Exhibit 10.3.8 to Ormat Technologies, Inc.'s Registration Statement on Form S-1 (File No. 333-117527) filed with the Securities and Exchange Commission on July 21, 2004.

10.2.3 Amendment No. 2, dated as of July 27, 1990, between Southern California Edison Company and Second Imperial Geothermal Company, incorporated by reference to Exhibit 10.3.9 to Ormat Technologies, Inc.'s Registration Statement on Form S-1 (File No. 333-117527) filed with the Securities and Exchange Commission on July 21, 2004.

10.2.4 Amendment No. 3, dated as of November 24, 1992, between Southern California Edison Company and Second Imperial Geothermal Company, incorporated by reference to Exhibit 10.3.10 to Ormat Technologies, Inc.'s Registration Statement on Form S-1 (File No. 333-117527) filed with the Securities and Exchange Commission on July 21, 2004.

10.2.5 Power Purchase Contract, dated April 15, 1985, between Mammoth Pacific and Southern California Edison Company, incorporated by reference to Exhibit 10.3.13 to Ormat Technologies, Inc.'s Registration Statement Amendment No. 1 on Form S-1/A (File No. 333-117527) to the Securities and Exchange Commission on September 28, 2004.

10.2.6 Amendment No. 1, dated as of October 27, 1989, between Mammoth Pacific and Southern California Edison Company, incorporated by reference to Exhibit 10.3.14 to Ormat Technologies, Inc. Registration Statement Amendment No. 1 on Form S-1/A (File No. 333-117527) to the Securities and Exchange Commission on September 28, 2004.

10.2.7 Amendment No. 2, dated as of December 20, 1989, between Mammoth Pacific and Southern California Edison Company, incorporated by reference to Exhibit 10.3.15 to Ormat Technologies, Inc. Registration Statement on Form S-1 (File No. 333-117527) to the Securities and Exchange Commission on July 20, 2004.

10.2.8 Interconnection Facilities Agreement, dated October 13, 1985, by and between Southern California Edison Company and Mammoth Pacific (II), incorporated by reference to Exhibit 10.3.20 to Ormat Technologies, Inc.'s Registration Statement Amendment No. 1 on Form S-1/A (File No. 333-117527) filed with the Securities and Exchange Commission on September 28, 2004.

10.2.9 Plant Connection Agreement for the Second Imperial Geothermal Company Power Plant No. 1, dated, October 27, 1992, by and between Imperial Irrigation District and Second Imperial Geothermal Company incorporated by reference to Exhibit 10.3.24 to Ormat Technologies, Inc.'s Registration Statement Amendment No. 1 on Form S-1/A (File No. 333-117527) filed with the Securities and Exchange Commission on September 28, 2004.

10.2.10 IID-SIGC Transmission Service Agreement for Alternative Resources, dated, October 27, 1992, by and between Imperial Irrigation District and Second Imperial Geothermal Company incorporated by reference to Exhibit 10.3.25 to Ormat Technologies, Inc.'s Registration Statement on Form S-1 (File No. 333-117527) filed with the Securities and Exchange Commission on July 21, 2004.

10.2.11 IID-Edison Transmission Service Agreement for Alternative Resources, dated, September 26, 1985, by and between Imperial Irrigation District and Southern California Edison Company incorporated by reference to Exhibit 10.3.34 to Ormat Technologies, Inc.'s Registration Statement Amendment No. 1 on Form S-1/A (File No. 333-117527) filed with the Securities and Exchange Commission on September 28, 2004.

10.2.15 Purchase Power Contract, dated March 24, 1986, by and between Hawaii Electric Light Company and Thermal Power Company incorporated by reference to Exhibit 10.3.44 to Ormat Technologies, Inc.'s Registration Statement Amendment No. 1 on Form S-1/A (File No. 333-117527) filed with the Securities and Exchange Commission on September 28, 2004.

10.2.16 Firm Capacity Amendment to Purchase Power Contract, dated July 28, 1989, by and between Hawaii Electric Light Company and Puna Geothermal Venture incorporated by reference to Exhibit 10.3.45 to Ormat Technologies, Inc.'s Registration Statement Amendment No. 1 on Form S-1/A (File No. 333-117527) filed with the Securities and Exchange Commission on September 28, 2004.

10.2.17 Amendment to Purchase Power Contract, dated October 19, 1993, by and between Hawaii Electric Light Company and Puna Geothermal Venture incorporated by reference to Exhibit 10.3.46 to Ormat Technologies, Inc.'s Registration Statement Amendment No. 1 on Form S-1/A (File No. 333-117527) filed with the Securities and Exchange Commission on September 28, 2004.

10.2.18 Third Amendment to the Purchase Power Contract, dated March 7, 1995, by and between Hawaii Electric Light Company and Puna Geothermal Venture incorporated by reference to Exhibit 10.3.47 to Ormat Technologies, Inc.'s Registration Statement Amendment No. 1 on Form S-1/A (File No. 333-117527) filed with the Securities and Exchange Commission on September 28, 2004.

10.2.19 Performance Agreement and Fourth Amendment to the Purchase Power Contract, dated February 12, 1996, by and between Hawaii Electric Light Company and Puna Geothermal Venture incorporated by reference to Exhibit 10.3.48 to Ormat Technologies, Inc.'s Registration Statement Amendment No. 1 on Form S-1/A (File No. 333-117527) filed with the Securities and Exchange Commission on September 28, 2004.

10.2.20 Power Purchase Agreement, dated October 20, 2016, between ONGP, LLC and Southern California Public Power Authority, incorporated by reference to Exhibit 10.1 to Ormat Technologies, Inc.'s Current Report on Form 8-K filed with the Securities Exchange Commission on June 1, 2017.

10.3.1 Ormesa BLM Geothermal Resources Lease CA 966 incorporated by reference to Exhibit 10.4.1 to Ormat Technologies, Inc.'s Registration Statement Amendment No. 1 on Form S-1/A (File No. 333-117527) filed with the Securities and Exchange Commission on September 28, 2004.

10.3.2 Ormesa BLM License for Electric Power Plant Site CA 24678 incorporated by reference to Exhibit 10.4.2 to Ormat Technologies, Inc.'s Registration Statement Amendment No. 1 on Form S-1/A (File No. 333-117527) filed with the Securities and Exchange Commission on September 28, 2004.

10.3.3 Geothermal Resources Mining Lease, dated February 20, 1981, by and between the State of Hawaii, as Lessor, and Kapoho Land Partnership, as Lessee incorporated by reference to Exhibit 10.4.3 to Ormat Technologies, Inc.'s Registration Statement Amendment No. 1 on Form S-1/A (File No. 333-117527) filed with the Securities and Exchange Commission on September 28, 2004.

10.3.4 Geothermal Lease Agreement, dated October 20, 1975, by and between Ruth Walker Cox and Betty M. Smith, as Lessor, and Gulf Oil Corporation, as Lessee incorporated by reference to Exhibit 10.4.4 to Ormat Technologies, Inc.'s Registration Statement Amendment No. 1 on Form S-1/A (File No. 333-117527) filed with the Securities and Exchange Commission on September 28, 2004.

10.3.5 Geothermal Lease Agreement, dated August 1, 1976, by and between Southern Pacific Land Company, as Lessor, and Phillips Petroleum Company, as Lessee incorporated by reference to Exhibit 10.4.5 to Ormat Technologies, Inc.'s Registration Statement Amendment No. 1 on Form S-1/A (File No. 333-117527) filed with the Securities and Exchange Commission on September 28, 2004.

10.3.6 Geothermal Resources Lease, dated November 18, 1983, by and between Sierra Pacific Power Company, as Lessor, and Geothermal Development Associates, as Lessee incorporated by reference to Exhibit 10.4.6 to Ormat Technologies, Inc.'s Registration Statement Amendment No. 1 on Form S-1/A (File No. 333-117527) filed with the Securities and Exchange Commission on September 28, 2004.

10.3.7 Lease Agreement, dated November 1, 1969, by and between Chrisman B. Jackson and Sharon Jackson, husband and wife, as Lessor, and Standard Oil Company of California, as Lessee incorporated by reference to Exhibit 10.4.7 to Ormat Technologies, Inc.'s Registration Statement on Form S-1 (File No. 333-117527) filed with the Securities and Exchange Commission on July 21, 2004.

10.3.8 Lease Agreement, dated September 22, 1976, by and between El Toro Land & Cattle Co., as Lessor, and Standard Oil Company of California, as Lessee incorporated by reference to Exhibit 10.4.8 to Ormat Technologies, Inc.'s Registration Statement on Form S-1 (File No. 333-117527) filed with the Securities and Exchange Commission on July 21, 2004.

10.3.9 Lease Agreement, dated February 17, 1977, by and between Joseph L. Holtz, as Lessor, and Chevron U.S.A. Inc., as Lessee incorporated by reference to Exhibit 10.4.9 to Ormat Technologies, Inc.'s Registration Statement on Form S-1 (File No. 333-117527) filed with the Securities and Exchange Commission on July 21, 2004.

10.3.10 Lease Agreement, dated March 11, 1964, by and between John D. Jackson and Frances Jones Jackson, also known as Frances J. Jackson, husband and wife, as Lessor, and Standard Oil Company of California, as Lessee incorporated by reference to Exhibit 10.4.10 to Ormat Technologies, Inc.'s Registration Statement on Form S-1 (File No. 333-117527) filed with the Securities and Exchange Commission on July 21, 2004.

10.3.11 Lease Agreement, dated February 16, 1964, by and between John D. Jackson, conservator for the estate of Aphia Jackson Wallan, as Lessor, and Standard Oil Company of California, as Lessee incorporated by reference to Exhibit 10.4.11 to Ormat Technologies, Inc.'s Registration Statement on Form S-1 (File No. 333-117527) filed with the Securities and Exchange Commission on July 21, 2004.

10.3.12 Lease Agreement, dated March 17, 1964, by and between Helen S. Fugate, a widow, as Lessor, and Standard Oil Company of California, as Lessee incorporated by reference to Exhibit 10.4.12 to Ormat Technologies, Inc.'s Registration Statement Amendment No. 1 on Form S-1/A (File No. 333-117527) filed with the Securities and Exchange Commission on September 28, 2004.

10.3.13 Lease Agreement, dated February 16, 1964, by and between John D. Jackson and Frances J. Jackson, husband and wife, as Lessor, and Standard Oil Company of California, as Lessee incorporated by reference to Exhibit 10.4.13 to Ormat Technologies, Inc.'s Registration Statement Amendment No. 1 on Form S-1/A (File No. 333-117527) filed with the Securities and Exchange Commission on September 28, 2004.

10.3.14 Lease Agreement, dated February 20, 1964, by and between John A. Straub and Edith D. Straub, also known as John A. Straub and Edythe D. Straub, husband and wife, as Lessor, and Standard Oil Company of California, as Lessee incorporated by reference to Exhibit 10.4.14 to Ormat Technologies, Inc.'s Registration Statement on Form S-1 (File No. 333-117527) filed with the Securities and Exchange Commission on July 21, 2004.

10.3.15 Lease Agreement, dated July 1, 1971, by and between Marie L. Gisler and Harry R. Gisler, as Lessor, and Standard Oil Company of California, as Lessee incorporated by reference to Exhibit 10.4.15 to Ormat Technologies, Inc.'s Registration Statement on Form S-1 (File No. 333-117527) filed with the Securities and Exchange Commission on July 21, 2004.

10.3.16 Lease Agreement, dated February 28, 1964, by and between Gus Kurupas and Guadalupe Kurupas, husband and wife, as Lessor, and Standard Oil Company of California, as Lessee incorporated by reference to Exhibit 10.4.16 to Ormat Technologies, Inc.'s Registration Statement on Form S-1 (File No. 333-117527) filed with the Securities and Exchange Commission on July 21, 2004.

10.3.17 Lease Agreement, dated April 7, 1972, by and between Nowlin Partnership, as Lessor, and Standard Oil Company of California, as Lessee incorporated by reference to Exhibit 10.4.17 to Ormat Technologies, Inc.'s Registration Statement on Form S-1 (File No. 333-117527) filed with the Securities and Exchange Commission on July 21, 2004.

10.3.18 Geothermal Lease Agreement, dated July 18, 1979, by and between Charles K. Corfman, an unmarried man as his sole and separate property, and Lessor, and Union Oil Company of California, as Lessee incorporated by reference to Exhibit 10.4.18 to Ormat Technologies, Inc.'s Registration Statement Amendment No. 1 on Form S-1/A (File No. 333-117527) filed with the Securities and Exchange Commission on September 28, 2004.

10.3.19 Lease Agreement, dated January 1, 1972, by and between Holly Oberly Thomson, also known as Holly F. Oberly Thomson, also known as Holly Felicia Thomson, as Lessor, and Union Oil Company of California, as Lessee incorporated by reference to Exhibit 10.4.19 to Ormat Technologies, Inc.'s Registration Statement Amendment No. 1 on Form S-1/A (File No. 333-117527) filed with the Securities and Exchange Commission on September 28, 2004.

10.3.20 Lease Agreement, dated June 14, 1971, by and between Fitzhugh Lee Brewer, Jr., a married man as his separate property, Donna Hawk, a married woman as her separate property, and Ted Draper and Helen Draper, husband and wife, as Lessor, and Union Oil Company of California, as Lessee incorporated by reference to Exhibit 10.4.20 to Ormat Technologies, Inc.'s Registration Statement Amendment No. 1 on Form S-1/A (File No. 333-117527) filed with the Securities and Exchange Commission on September 28, 2004.

10.3.21 Lease Agreement, dated May 13, 1971, by and between Mathew J. La Brucherie and Jane E. La Brucherie, husband and wife, and Robert T. O'Dell and Phyllis M. O'Dell, husband and wife, as Lessor, and Union Oil Company of California, as Lessee incorporated by reference to Exhibit 10.4.21 to Ormat Technologies, Inc.'s Registration Statement on Form S-1 (File No. 333-117527) filed with the Securities and Exchange Commission on July 21, 2004.

10.3.22 Lease Agreement, dated June 2, 1971, by and between Dorothy Gisler, a widow, Joan C. Hill, and Jean C. Browning, as Lessor, and Union Oil Company of California, as Lessee incorporated by reference to Exhibit 10.4.22 to Ormat Technologies, Inc.'s Registration Statement Amendment No. 1 on Form S-1/A (File No. 333-117527) filed with the Securities and Exchange Commission on September 28, 2004.

10.3.23 Geothermal Lease Agreement, dated February 15, 1977, by and between Walter J. Holtz, as Lessor, and Magma Energy Inc., as Lessee incorporated by reference to Exhibit 10.4.23 to Ormat Technologies, Inc.'s Registration Statement Amendment No. 1 on Form S-1/A (File No. 333-117527) filed with the Securities and Exchange Commission on September 28, 2004.

10.3.24 Geothermal Lease, dated August 31, 1983, by and between Magma Energy Inc., as Lessor, and Holt Geothermal Company, as Lessee incorporated by reference to Exhibit 10.4.24 to Ormat Technologies, Inc.'s Registration Statement Amendment No. 1 on Form S-1/A (File No. 333-117527) filed with the Securities and Exchange Commission on September 28, 2004.

10.3.25 Geothermal Resources Lease, dated June 27, 1988, by and between Bernice Guisti, Judith Harvey and Karen Thompson, Trustees and Beneficiaries of the Guisti Trust, as Lessor, and Far West Capital, Inc., as Lessee incorporated by reference to Exhibit 10.4.26 to Ormat Technologies, Inc.'s Registration Statement Amendment No. 1 on Form S-1/A (File No. 333-117527) filed with the Securities and Exchange Commission on September 28, 2004.

10.3.26 Amendment to Geothermal Resources Lease, dated January, 1992, by and between Bernice Guisti, Judith Harvey and Karen Thompson, Trustees and Beneficiaries of the Guisti Trust, as Lessor, and Far West Capital, Inc., as Lessee incorporated by reference to Exhibit 10.4.27 to Ormat Technologies, Inc.'s Registration Statement Amendment No. 1 on Form S-1/A (File No. 333-117527) filed with the Securities and Exchange Commission on September 28, 2004.

10.3.27 Second Amendment to Geothermal Resources Lease, dated June 25, 1993, by and between Bernice Guisti, Judith Harvey and Karen Thompson, Trustees and Beneficiaries of the Guisti Trust, as Lessor, and Far West Capital, Inc. and its Assignee, Steamboat Development Corp., as Lessee incorporated by reference to Exhibit 10.4.28 to Ormat Technologies, Inc.'s Registration Statement Amendment No. 1 on Form S-1/A (File No. 333-117527) filed with the Securities and Exchange Commission on September 28, 2004.

10.3.28 Geothermal Resources Sublease, dated May 31, 1991, by and between Fleetwood Corporation, as Lessor, and Far West Capital, Inc., as Lessee incorporated by reference to Exhibit 10.4.29 to Ormat Technologies, Inc.'s Registration Statement Amendment No. 1 on Form S-1/A (File No. 333-117527) filed with the Securities and Exchange Commission on September 28, 2004.

10.3.29 KLP Lease and Agreement, dated March 1, 1981, by and between Kapoho Land Partnership, as Lessor, and Thermal Power Company, as Lessee incorporated by reference to Exhibit 10.4.30 to Ormat Technologies, Inc.'s Registration Statement Amendment No. 1 on Form S-1/A (File No. 333-117527) filed with the Securities and Exchange Commission on September 28, 2004.

10.3.30 Amendment to KLP Lease and Agreement, dated July 9, 1990, by and between Kapoho Land Partnership, as Lessor, and Puna Geothermal Venture, as Lessee incorporated by reference to Exhibit 10.4.31 to Ormat Technologies, Inc.'s Registration Statement Amendment No. 1 on Form S-1/A (File No. 333-117527) filed with the Securities and Exchange Commission on September 28, 2004.

10.3.31 Second Amendment to KLP Lease and Agreement, dated December 31, 1996, by and between Kapoho Land Partnership, as Lessor, and Puna Geothermal Venture, as Lessee incorporated by reference to Exhibit 10.4.32 to Ormat Technologies, Inc.'s Registration Statement Amendment No. 1 on Form S-1/A (File No. 333-117527) filed with the Securities and Exchange Commission on September 28, 2004.

10.4.1* Amended and Restated Ormat Technologies, Inc. 2012 Incentive Compensation Plan, incorporated by reference to Exhibit 10.2 to Ormat Technologies, Inc.'s Current Report on Form 8-K filed with the Securities and Exchange Commission on February 11, 2014.

10.4.2** Form of Incentive Stock Option Agreement to Ormat Technologies, Inc.'s 2012 Incentive Compensation Plan, incorporated by reference to Exhibit 10.31.2 to Ormat Technologies, Inc.'s Annual Report on Form 10-K filed with the Securities and Exchange Commission on February 28, 2014

10.4.3* Form of Freestanding Stock Appreciation Right Agreement to Amended and Restated Ormat Technologies, Inc.'s 2012 Incentive Compensation Plan, , incorporated by reference to Exhibit 10.31.3 to Ormat Technologies, Inc.'s Annual Report on Form 10-K filed with the Securities and Exchange Commission on February 28, 2014.

10.4.4* Ormat Technologies, Inc.'s Annual Management Incentive Plan, incorporated by reference to Exhibit 10.1 to Ormat Technologies, Inc.'s Current Report on Form 8-K filed with the Securities and Exchange Commission on February 29, 2016.

10.4.5* Form of Restricted Stock Unit Agreement under the Amended and Restated Ormat Technologies, Inc. 2012 Incentive Compensation Plan, incorporated by reference to Exhibit 10.1 to Ormat Technologies, Inc.'s Current Report on Form 8-K filed with the Securities Exchange Commission on November 9, 2017.

10.4.6* Ormat Technologies, Inc. 2018 Incentive Compensation Plan, incorporated by reference to Appendix A to Ormat Technologies, Inc.'s Definitive Proxy Statement on Schedule 14A filed on March 27, 2018.

10.4.7* Form of Stock Appreciation Right Agreement under the Company's 2018 Incentive Compensation Plan for stock appreciation rights awarded to Mr. Isaac Angel, incorporated by reference to Exhibit 10.1 to Ormat Technologies, Inc.'s Current Report on Form 8-K filed on May 9, 2018.

10.4.8* Form of Restricted Stock Unit Agreement under the Company's 2018 Incentive Compensation Plan for restricted stock units awarded to Mr. Isaac Angel, incorporated by reference to Exhibit 10.2 to Ormat Technologies, Inc.'s Current Report on Form 8-K filed on May 9, 2018.

10.4.9* Form of Restricted Stock Unit Grant Notice and Terms and Conditions (Employees-Time Based Units), incorporated by reference to Exhibit 10.5 to Ormat Technologies, Inc.'s Quarterly Report on Form 10-Q filed on August 8, 2018.

10.4.10* Form of Stock Appreciation Right Grant Notice and Terms and Conditions (Employees), incorporated by reference to Exhibit 10.6 to Ormat Technologies, Inc.'s Quarterly Report on Form 10-Q filed on August 8, 2018.

10.4.11* Form of Restricted Stock Unit Grant Notice and Terms and Conditions (Directors) to Ormat Technologies, Inc.'s 2018 Incentive Compensation Plan, incorporated by reference to Exhibit 10.4.11 to Ormat Technologies, Inc.'s Annual Report on Form 10-K filed with the Securities and Exchange Commission on March 01, 2019

10.4.12* Form of Stock Appreciation Right Grant Notice and Terms and Conditions (Directors) to Ormat Technologies, Inc.'s 2018 Incentive Compensation Plan.1, incorporated by reference to Exhibit 10.4.12 to Ormat Technologies, Inc.'s Annual Report on Form 10-K filed with the Securities and Exchange Commission on March 01, 2019

10.5.1* Form of Indemnification Agreement incorporated by reference to Exhibit 10.11 to Ormat Technologies, Inc.'s Registration Statement Amendment No. 2 on Form S-1 (File No. 333-117527) filed with the Securities and Exchange Commission on October 20, 2004.

10.6.2 Note Purchase Agreement, dated November 29, 2016, among ORNI 47 LLC, MUFG Union Bank, N.A., Munich Reinsurance America, Inc. and Munich American Reassurance Company, incorporated by reference to Exhibit 4.1 to Ormat Technologies Inc.'s Current Report on Form 8-K/A filed with the Securities and Exchange Commission on December 6, 2016.

10.14.1 Amended and Restated Power Purchase Agreement for Olkaria III Geothermal Plant, dated January 19, 2007, between OrPower 4 Inc. and The Kenya Power and Lighting Company Limited, incorporated by reference to Exhibit 10.20.1 to Ormat Technologies, Inc.'s Annual Report on Form 10-K filed with the Securities and Exchange Commission on March 12, 2007.

10.14.2 Olkaria III Project Security Agreement, dated January 19, 2007, between OrPower 4 Inc. and The Kenya Power and Lighting Company Limited, incorporated by reference to Exhibit 10.20.2 to Ormat Technologies, Inc.'s Annual Report on Form 10-K filed with the Securities and Exchange Commission on March 12, 2007.

10.16 Joint Ownership Agreement for the Carson Lake Project, dated as of March 12, 2008, by and between Nevada Power Company and ORNI 16 LLC, incorporated by reference to Exhibit 10.24 to Ormat Technologies, Inc.'s Quarterly Report on Form 10-Q filed with the Securities and Exchange Commission on May 7, 2008.

10.17 Sale and Purchase Agreement dated August 2, 2010, between ORNI 44 LLC and CD Mammoth Lakes I, Inc. and CD Mammoth Lakes II, Inc., incorporated by reference to Exhibit 10.1 to Ormat Technologies, Inc.'s Quarterly Report on Form 10-Q filed with the Securities and Exchange Commission on November 4, 2010.

10.18 Note Purchase Agreement, dated September 23, 2011, among OFC 2 LLC, ORNI 15 LLC, ORNI 39 LLC, ORNI 42 LLC, and HSS II, LLC, as Issuers, OFC 2 Noteholder Trust, as Purchaser, John Hancock Life Insurance Company (U.S.A.), as Administrative Agent, and the United States Department of Energy (DOE), as Guarantor, incorporated by reference to Exhibit 10.1 to Ormat Technologies, Inc.'s Quarterly Report on Form 10-Q filed with the Securities and Exchange Commission on November 4, 2011.

10.19.1 Finance Agreement, dated as of August 23, 2012, between OrPower 4, Inc., an indirect wholly-owned subsidiary of Ormat Technologies, Inc., and Overseas Private Investment Corporation, incorporated by reference to Exhibit 10.1 to Ormat Technologies, Inc.'s Quarterly Report on Form 10-Q filed with the Securities and Exchange Commission on November 8, 2012.

10.19.2 Amendment No. 1 to the Finance Agreement, dated as of August 23, 2012, between OrPower 4, Inc., an indirect wholly-owned subsidiary of Ormat Technologies, Inc., and Overseas Private Investment Corporation, incorporated by reference to Exhibit 10.1 to Ormat Technologies, Inc.'s Quarterly Report on Form 10-Q filed with the Securities and Exchange Commission on November 8, 2012.

10.19.3 Loan Agreement, dated March 22, 2018, by and among Ormat Technologies, Inc. and Migdal Insurance Company Ltd., Migdal's Makefet Pension and Provident Funds Ltd. and Yozma Pension Fund of Self Employed Ltd., incorporated by reference to Exhibit 10.1 to Ormat Technologies, Inc.'s Quarterly Report on Form 10-Q filed with the Securities and Exchange Commission on June 19, 2018.

10.19.4 Finance Agreement, dated April 30, 2018 between Geotermica Platanares, S.A. DE C.V. and Overseas Private Investment Corporation incorporated by reference to Exhibit 10.2 to Ormat Technologies, Inc.'s Quarterly Report on Form 10-Q filed with the Securities and Exchange Commission on June 19, 2018.

10.19.5 Amendment to Finance Agreement, dated October 17, 2018 between Geotermica Platanares, S.A. DE C.V. and Overseas Private Investment Corporation, incorporated by reference to Exhibit 10.1 to Ormat Technologies, Inc.'s Quarterly Report on Form 10-Q filed on November 8, 2018.

10.22.1* Employment Agreement, dated as of February 11, 2014, between Ormat Technologies, Inc. and Isaac Angel, incorporated by reference to Exhibit 10.1 to Ormat Technologies, Inc.'s Current Report on Form 8-K filed with the Securities and Exchange Commission on February 11, 2014.

10.22.2* Employment Agreement, dated as of January 6, 2013, between Ormat Systems, Ltd. and Doron Blachar, incorporated by reference to Exhibit 10.30.2 to Ormat Technologies, Inc.'s Annual Report on Form 10-K filed with the Securities and Exchange on February 28, 2014.

10.23.1 JBIC Facility Agreement, dated March 28, 2014, by and among Kyuden Sarulla Pte. Ltd., OrSarulla Inc., PT Medco Geopower Sarulla, Sarulla Operations Ltd, Sarulla Power Asset Limited, Japan Bank for International Cooperation and Mizuho Bank, Ltd., dated March 28, 2014, incorporated by reference to Exhibit 10.7 to Ormat Technologies, Inc.'s Quarterly Report on Form 10-Q filed with the Securities and Exchange Commission on May 9, 2014.

10.23.2 Common Terms Agreement, dated March 28, 2014, by and among Kyuden Sarulla Pte. Ltd., OrSarulla Inc., PT Medco Geopower Sarulla, Sarulla Operations Ltd, Sarulla Power Asset Limited, Japan Bank for International Cooperation, Asian Development Bank, The Bank of Tokyo-Mitsubishi UFJ, Ltd., ING Bank N.V., Tokyo Branch, National Australia Bank Limited, Mizuho Bank, Ltd., Mizuho Bank (USA), Pt. Bank Mizuho Indonesia, Société Générale, Société Générale Tokyo Branch, and Sumitomo Mitsui Banking Corporation, dated March 28, 2014, incorporated by reference to Exhibit 10.8 to Ormat Technologies, Inc.'s Quarterly Report on Form 10-Q filed with the Securities and Exchange Commission on May 9, 2014.

10.23.3 Covered Lenders Facility Agreement, dated March 28, 2014, by and among Kyuden Sarulla Pte. Ltd., Orsarulla Inc., PT Medco Geopower Sarulla, Sarulla Operations Ltd, Sarulla Power Asset Limited, The Bank of Tokyo-Mitsubishi UFJ, Ltd., ING Bank N.V., Tokyo Branch, National Australia Bank Limited, Société Générale, Tokyo Branch, and Sumitomo Mitsui Banking Corporation, dated March 28, 2014, incorporated by reference to Exhibit 10.9 to Ormat Technologies, Inc.'s Quarterly Report on Form 10-Q filed with the Securities and Exchange Commission on May 9, 2014.

10.23.4 ADB Facility Agreement, dated March 28, 2014, by and among Kyuden Sarulla Pte. Ltd., OrSarulla Inc., PT Medco Geopower Sarulla, Sarulla Operations Ltd, Sarulla Power Asset Limited and Asian Development Bank, dated March 28, 2014, incorporated by reference to Exhibit 10.10 to Ormat Technologies, Inc.'s Quarterly Report on Form 10-Q filed with the Securities and Exchange Commission on May 9, 2014.

10.23.5 Ormat Equity Support Deed, dated March 28, 2014, by and among Ormat International, Inc., Ormat Holding Corp., OrPower 11 Inc., OrSarulla Inc., Sarulla Operations Ltd, Mizuho Bank, Ltd. and Mizuho Bank (USA), dated March 28, 2014, incorporated by reference to Exhibit 10.11 to Ormat Technologies, Inc.'s Quarterly Report on Form 10-Q filed with the Securities and Exchange Commission on May 9, 2014.

10.24.1	Commercial Cooperation Agreement, dated May 4, 2017, between Ormat Technologies, Inc. and ORIX Corporation, incorporated by reference to Exhibit 10.1 to Ormat Technologies, Inc.'s Current Report on Form 8-K filed with the Securities and Exchange Commission on May 4, 2017.
10.24.2	Governance Agreement, dated May 4, 2017, between Ormat Technologies, Inc. and ORIX Corporation, incorporated by reference to Exhibit 10.2 to Ormat Technologies, Inc.'s Current Report on Form 8-K filed with the Securities and Exchange Commission on May 4, 2017.
10.24.3	Registration Rights Agreement, dated May 4, 2017, between Ormat Technologies, Inc. and ORIX Corporation, incorporated by reference to Exhibit 10.3 to Ormat Technologies, Inc.'s Current Report on Form 8-K filed with the Securities and Exchange Commission on May 4, 2017.
21.1	Subsidiaries of Ormat Technologies, Inc., incorporated by reference to Exhibit 21.1 to Ormat Technologies, Inc.'s Annual Report on Form 10-K filed with the Securities and Exchange Commission on March 28, 2006.
23.1+	Consent of Kesselman & Kesselman, Certified Public Accountants (Isr.), a member firm of PricewaterhouseCoopers International Limited, Independent Registered Public Accounting Firm.
23.2+	Consent of PricewaterhouseCoopers LLP, Independent Registered Public Accounting Firm.
31.1+	Certification of the Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2+	Certification of the Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1+	Certification of the Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2+	Certification of the Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
99.1	Material terms with respect to BLM geothermal resources leases incorporated by reference to Exhibit 99.1 to Ormat Technologies, Inc.'s Registration Statement Amendment No. 2 on Form S-1 (File No. 333-117527) filed with the Securities and Exchange Commission on July 21, 2004.
99.2	Material terms with respect to BLM site leases incorporated by reference to Exhibit 99.2 to Ormat Technologies, Inc.'s Registration Statement on Form S-1 (File No. 333-117527) filed with the Securities and Exchange Commission on July 20, 2004.
99.3	Material terms with respect to agreements addressing renewable energy pricing and payment issues incorporated by reference to Exhibit 99.3 to Ormat Technologies, Inc.'s Registration Statement on Form S-1A (File No. 333-117527) filed with the Securities and Exchange Commission on September 28, 2004.

101.INS+ XBRL Instance Document.
101.SCH+ XBRL Taxonomy Extension Schema Document.
101.CAL+ XBRL Taxonomy Extension Calculation Linkbase Document.
101.DEF+ XBRL Taxonomy Extension Definition Linkbase Document.
101.LAB+ XBRL Taxonomy Extension Label Linkbase Document.
101.PRE+ XBRL Taxonomy Extension Presentation Linkbase Document.
104.1+ Cover Page Interactive Data File (Embedded within the Inline XBRL document and included in Exhibit 101).

* Management contract or compensatory plan in which directors and/or executive officers are eligible to participate.

\+ Filed herewith.

Schedules have been omitted pursuant to Item 601(b)(2) of Regulation S-K. We will furnish the omitted schedules to the SEC upon request.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

ORMAT TECHNOLOGIES, INC.

By: /s/ Isaac Angel
Name: Isaac Angel
Title: Chief Executive Officer

Date: March 2, 2020

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the Registrant and in the capacities indicated, on March 2, 2020.

Signature	**Capacity**
/s/ Isaac Angel Isaac Angel	Chief Executive Officer (Principal Executive Officer)
/s/ Doron Blachar Doron Blachar	President and Chief Financial Officer (President and Principal Financial and Accounting Officer)
/s/ Todd Freeland Todd Freeland	Chairman of the Board of Directors
/s/ Stan Koyanagi Stan Koyanagi	Director
/s/ Dan Falk Dan Falk	Director
/s/ David Granot David Granot	Director
/s/ Ravit Bar Niv Ravit Bar Niv	Director
/s/ Yuichi Nishigori Yuichi Nishigori	Director
/s/ Dafna Sharir Dafna Sharir	Director
/s/ Stanley B. Stern Stanley B. Stern	Director
/s/ Byron Wong Byron Wong	Director

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Exhibit 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statements on Form S-8 (No. 333-129583, 333-143488, 333-181509 and 333-224752) of Ormat Technologies, Inc. of our report dated March 2, 2020 relating to the financial statements and the effectiveness of internal control over financial reporting, which appears in this Form 10-K.

/s/ Kesselman & Kesselman
Certified Public Accountants (Isr.)
A member firm of PricewaterhouseCoopers International Limited
Tel Aviv, Israel
March 2, 2020

Exhibit 23.2

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statements on Form S-8 (No. 333-129583, 333-143488, 333-181509, and 333-224752) of Ormat Technologies, Inc. of our report dated March 16, 2018, except for the effects of the restatement and revision discussed in Note 1 (not presented herein) to the consolidated financial statements appearing under Item 8 of the Company's 2017 annual report on Form 10-K/A, as to which the date is June 19, 2018, and except for the effects of the retrospective adjustments as a result of adoption of accounting policies and changes in segments as discussed in Note 1(a) (not presented herein) to the consolidated financial statements appearing under Item 8 of the Company's 2018 annual report on Form 10-K, as to which the date is March 1, 2019 relating to the financial statements, which appears in this Form 10-K.

/s/ PricewaterhouseCoopers LLP
San Francisco, California
March 2, 2020

Exhibit 31.1

Ormat Technologies, Inc.
Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002

I, Isaac Angel, certify that:

1. I have reviewed this annual report on Form 10-K of Ormat Technologies, Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

By: /s/ Isaac Angel
Name: Isaac Angel
Title: Chief Executive Officer

Date: March 2, 2020

Exhibit 31.2

Ormat Technologies, Inc.
Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002

I, Doron Blachar, certify that:

1. I have reviewed this annual report on Form 10-K of Ormat Technologies, Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

By: /s/ DORON BLACHAR
Name: Doron Blachar
Title: President and Chief Financial Officer

Date: March 2, 2020

Exhibit 32.1

CERTIFICATION OF CHIEF EXECUTIVE OFFICER
PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

I, Isaac Angel, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that the annual report of Ormat Technologies, Inc. on Form 10-K for the year ended December 31, 2019 fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and that information contained in such annual report on Form 10-K fairly presents in all material respects the financial condition, results of operations and cash flows of Ormat Technologies, Inc. as of and for the periods presented in such annual report on Form 10-K. This written statement is being furnished to the Securities and Exchange Commission as an exhibit accompanying such annual report and shall not be deemed filed pursuant to the Securities Exchange Act of 1934.

By: /s/ Isaac Angel
Name: Isaac Angel
Title: Chief Executive Officer

Date: March 2, 2020

Exhibit 32.2

CERTIFICATION OF CHIEF FINANCIAL OFFICER
PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

I, Doron Blachar, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that the annual report of Ormat Technologies, Inc. on Form 10-K for the year ended December 31, 2019 fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and that information contained in such annual report on Form 10-K fairly presents in all material respects the financial condition, results of operations and cash flows of Ormat Technologies, Inc. as of and for the periods presented in such annual report on Form 10-K. This written statement is being furnished to the Securities and Exchange Commission as an exhibit accompanying such annual report and shall not be deemed filed pursuant to the Securities Exchange Act of 1934.

By: /s/ DORON BLACHAR
Name: Doron Blachar
Title: President and Chief Financial Officer

Date: March 2, 2020

ORMAT TECHNOLOGIES, INC.

2019 ANNUAL REPORT

The 48 MW McGinness Hills Expansion Geothermal Power Plant in the USA
Commenced operation at the end of 2018

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