2025

ANNUAL REPORT

ORMAT

Ormat employees at the 20MW Amatitlan geothermal facility in Guatemala during the Company's 60th anniversary.

WITH OVER

60 YEARS

OF EXPERIENCE

IN 2025

$990M

REVENUES

APPROXIMATELY

1,650

EMPLOYEES

OWN & OPERATE

~1.8GW

GEOTHERMAL, STORAGE, SOLAR & REG[1, 4]

IN 2025

$124M

NET INCOME[2]

IN 2025

$582M

ADJ. EBITDA[3]

[1] REG – Recovered Energy Generation
[2] Net Income attributable to the Company's stockholders
[3] See appendix for reconciliation of non-GAAP financial measures
[4] Reflects total capacity including additions since December 31, 2025, through Q1 2026

A leading renewable energy provider with a proven track record in geothermal and energy storage.

DEAR FELLOW SHAREHOLDERS,

2025 was another successful year for Ormat as we continued to execute our strategy and make meaningful progress toward our long-term growth plans and earnings targets. These achievements were reflected not only in solid financial performance, but also in the continued strategic expansion of our portfolio and the signing of new long-term power purchase agreements (PPAs) that enhance the visibility of our future earnings and strengthen our long-term earnings power. During the year, we grew revenue and adjusted EBITDA in line with our plans, benefited from our strategy to maintain merchant exposure in some of our storage assets, advanced next-generation geothermal technologies, and continued supporting global decarbonization efforts by providing clean, reliable, and sustainable energy.

Strategic Expansion Supporting Long-Term Growth

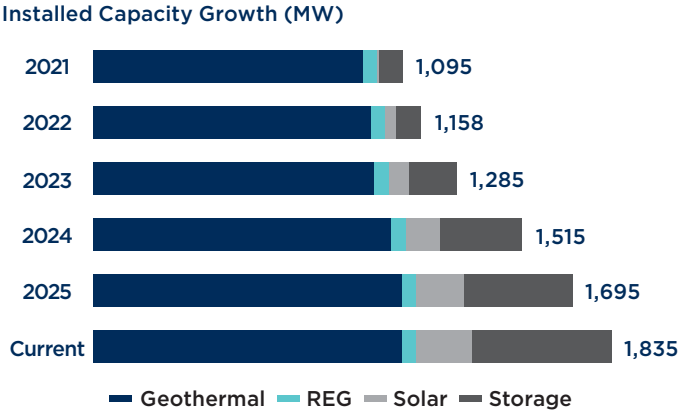
Our growth momentum in 2025 and early 2026 was highlighted by the expansion of our generating capacity by 320MW, achieved through a combination of organic development and the strategic acquisition of the Blue Mountain power plant and post-year-end acquisition of the Hoku solar-plus-storage facility, both in the USA.

Of this new capacity, approximately 115MW was added to our core Electricity segment and 205MW to our Energy Storage segment, reflecting our continued progress in diversifying and strengthening our portfolio. This expansion reinforces the consistent execution of our strategy and positions Ormat for sustained growth in 2026 and beyond.

Within our Electricity segment, we continue to see compelling opportunities, driven by accelerating demand for reliable, zero-emission power, particularly from data centers. This growing demand is supporting attractive pricing for new PPAs.

We recently secured several important long-term contracts:

- A geothermal portfolio PPA of up to 150MW to supply Google data centers through NV Energy.
- A 20-year PPA with Switch, a premier provider of AI, cloud, and enterprise data centers, for approximately 13MW from our Salt Wells power plant.
- Blend-and-Extend amended PPAs for two power plants for a total of approximately 40MW that extend the original expiration date and improve the PPA pricing.



These agreements provide profitable revenue growth and increased visibility into our development pipeline and earnings, while also validating our expanded exploration and drilling initiatives, which we launched a few years ago.

Our Product segment also delivered strong growth, largely driven by new project wins in New Zealand, where geothermal energy is increasingly recognized as one of the most cost-effective and reliable sources of electricity, positioning Ormat well to capture additional opportunities.

In our Energy Storage segment, we took strategic actions in response to recent regulatory changes in order to ensure the continued execution of our growth strategy. These efforts included securing batteries and safe harboring a number of our storage projects preserving Investment Tax Credits (ITC) eligibility for our entire storage portfolio through 2028, and in some cases beyond, without Foreign Entity of Concern (FEOC) limitations. This milestone provides greater certainty around the development of our storage pipeline.

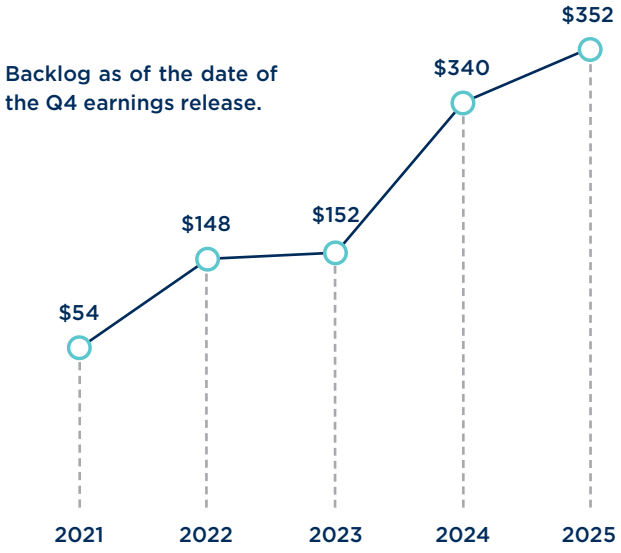
Financial Growth Driven by Energy Storage and Product Segments

Total revenues for 2025 reached $989.6 million, representing 12.5% year-over-year growth, driven primarily by strong performance in our Product and Energy Storage segments.

Our Energy Storage business delivered exceptional results, with revenues increasing 109.3% to $79.0 million. This performance reflects stronger energy rate in the PJM market, as well as contributions from storage facilities that came online during 2024 and 2025.

The Energy Storage business also delivered strong margins demonstrating the value of our balanced strategy of combining contracted pricing and merchant exposure for stability and upside capture. We believe this positive momentum will continue into 2026, as energy prices in the PJM market remain strong, recently commissioned facilities contribute for a full year, and additional projects in our pipeline reach commercial operation.

In the Product segment, revenue grew 55.2%, while EBITDA improved meaningfully as margins expanded, with gross margin increasing to 21.2%, from 18.4% in the prior year.



Doron Blachar
CEO

Operational Performance and Portfolio Development

Within our Electricity segment, we achieved another year of strong operational performance and portfolio growth. The performance was driven by the acquisition of Blue Mountain, the completion of the Beowawe repowering project, the return of Dixie Valley to full operations, the commercial operation of Ijen, and improved operational performance across our portfolio. Together, these contributions helped partially offset ongoing transmission-related curtailments in Nevada and California during 2025.

We also made meaningful progress on development activities in Indonesia, an attractive geothermal market and an important geographic diversifier. Most notably, we were awarded the highly competitive Telaga Ranu geothermal concession, strengthening our development pipeline in the region. Additionally, we signed two Geothermal Exploration and Energy Conversion Agreements (GEECA) for Songa Wayaua and Atadei, which together are expected to add approximately 40MW of geothermal capacity.

In our Product segment, our backlog grew to a record approximately $352 million that will be recognized in our results over the next two years.

Our Energy Storage segment also achieved key milestones with the successful commercial operations of our Lower Rio (60MW/120MWh) and Arrowleaf (35MW/140MWh) storage projects. In addition, subsequent to year-end we successfully commercialized operations at our Shirk (80MW/320MWh) storage project.

Subsequent to year-end, we acquired Hoku, a recently built operational solar-plus-battery storage facility on the Big Island of Hawaii, from Innergex Renewable Energy for $80.5 million. The facility includes a 30MW solar PV facility paired with a 30MW/120MWh battery energy storage system, with the battery charged exclusively from on-site solar generation. This transaction further strengthens our growing storage segment.

Looking ahead, we continue to build a robust development pipeline across geothermal, hybrid solar PV, and energy storage projects. In our Electricity segment, we currently have 149MW under construction that we expect will come online by the end of 2027. In our Energy Storage segment, we have five projects, with a total of 330MW/1,220MWh capacity under development, which we expect to achieve commercial operation by the end of 2028.

Advancing the Next-Generation of Geothermal Technology

In 2025, we also made significant progress advancing next-generation geothermal technologies, including Enhanced Geothermal Systems (EGS).

We signed a strategic commercial agreement with Sage Geosystems, enabling them to pilot their advanced pressure geothermal technology at an Ormat site in Nevada. We further demonstrated our confidence in this technology by participating as a co-lead investor in Sage's Series B financing.

We also entered into a strategic partnership with SLB, a global leader in subsurface technologies. This collaboration is designed to accelerate the development and commercialization of integrated geothermal assets, including EGS. As part of this partnership, we selected a site in Nevada for our first jointly developed EGS pilot project. This pilot will integrate engineered reservoir creation, advanced subsurface analysis, and surface facility integration, marking an important milestone in demonstrating the commercial viability of next-generation geothermal technology.

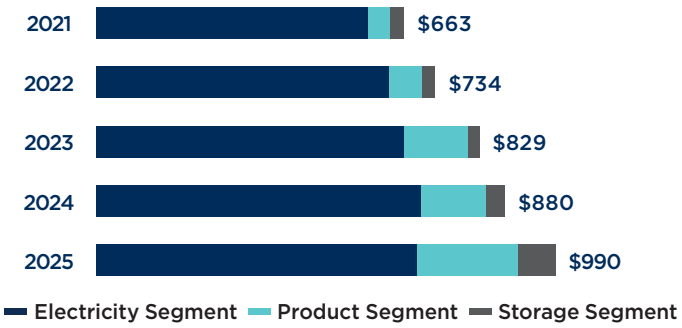
Looking Ahead

As we look to the future, we are confident in our ability to capitalize on the accelerating demand for clean, reliable baseload power. Our expanding geothermal and energy storage portfolio, record project backlog, and leadership in next-generation geothermal technologies position Ormat to deliver long-term value for our shareholders. We thank you for your continued trust and support as we work to power a more sustainable world.

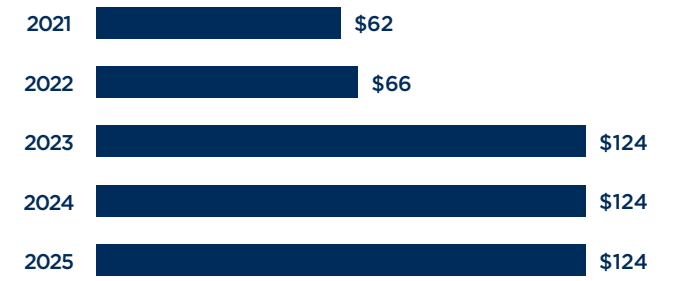
Regards,

Doron Blachar
Chief Executive Officer

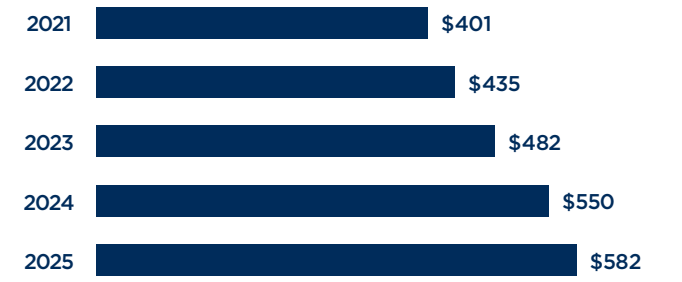
Revenue Growth ($M)



Net income attributable to the Company's stockholders ($M)



Adjusted EBITDA Growth* ($M)



* 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. 2024 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 on page 7 in this report.

“We remain on track with our capacity expansions across both Electricity and Storage segments, targeting a total portfolio capacity of 2.6GW to 2.8GW by the end of 2028.”

Doron Blachar
Chief Executive Officer

Ormat’s geology team during exploration activities

Ormat management and employees during a site visit with analysts and investors at the North Valley Complex, December 2025. 37MW Geothermal + 7MW Solar, NV, USA.

ORMAT'S 2024 SUSTAINABILITY HIGHLIGHTS[1]

ENVIRONMENT

23%
decrease in operational emissions intensity[2] since 2019

2.5M tCO_2e
avoided emissions compared to the local grid benchmarks

B ("MANAGEMENT")
CDP score maintained, reflecting our strengthened climate action

SOCIAL

OVER
60%
lower TRIR than industry average

27%
of VPs in the Company are women

31.1
average training hours per employee–a 26% increase from the previous year

GOVERNANCE

OVER
95%
employees trained on Anti-corruption and Anti-bribery policy

3 OUT OF 5
board committees are led by women

50%
of board members are women (44% increase from the end of 2024)

[1] Environmental data is taken from our most recent sustainability report, which provides information as of December 31, 2024.
[2] Scope 1 and 2 GHG emissions intensity by generation (tCO_2e/MWh).

RECONCILIATION OF EBITDA AND ADJUSTED EBITDA

We calculate EBITDA as net income before interest, taxes, depreciation, amortization, and accretion. We calculate Adjusted EBITDA as net income before interest, taxes, depreciation, amortization, and accretion, adjusted for (i) mark-to-market gains or losses from accounting for derivatives not designated as hedging instruments; (ii) stock-based compensation; (iii) merger and acquisition transaction costs; (iv) gain or loss from extinguishment of liabilities; (v) cost related to a settlement agreement; (vi) non-cash impairment charges; (vii) write-off of unsuccessful exploration activities; and (viii) other unusual or non-recurring items. We adjust for these factors as they may be non-cash, unusual in nature and/or are not factors used by management for evaluating operating performance. We believe that presentation of these measures will enhance an investor's ability to evaluate our financial and operating performance. 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. Our board of Directors and senior management use EBITDA and Adjusted EBITDA to evaluate our financial performance. However, other companies in our industry may calculate EBITDA and Adjusted EBITDA differently than we do.

Starting in the fourth quarter of 2022, we include accretion expenses related to asset retirement obligation in the adjustments to net income when calculating EBITDA and adjusted EBITDA. The presentation of EBITDA and adjusted EBITDA includes accretion expenses adjustment for the fiscal years ended December 31, 2025, 2024, 2023, 2022, and 2021.

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.

The following table reconciles net income to EBITDA and Adjusted EBITDA for the fiscal years ended December 31, 2025, 2024, 2023, 2022, and 2021.

	Year Ended December 31				
(Dollars In Thousands)	2025	2024	2023	2022	2021
Net income	**$126,990**	**$131,241**	**$133,137**	**$77,795**	**$76,077**
Interest expense, net (including amortization of deferred financing costs)	$135,836	$126,148	$86,898	$84,326	$80,534
Income tax provision (benefit)	($20,282)	($16,289)	$5,983	$14,742	$24,850
Adjustment to investment in unconsolidated companies: our proportionate share in interest expense, tax and depreciation and amortization in Sarulla and Ijen	$15,086	$17,637	$16,069	$13,199	$14,680
Depreciation, amortization, and accretion	$287,505	$259,151	$221,415	$198,603	$177,930
EBITDA	**$545,135**	**$517,888**	**$463,502**	**$388,665**	**$374,071**
Mark-to-market of derivative instruments	$550	$856	($2,206)	$1,613	$741
Stock-based compensation	$19,390	$20,197	$15,478	$11,646	$9,168
Make-whole premium related to long-term debt prepayment	–	–	–	$1,102	–
Reversal of a contingent liability related to a business combination transaction	–	–	–	($1,829)	($418)
Impairment of long-lived assets	$12,064	$1,280	–	$32,648	–
Allowance for bad debt related to February power crisis in Texas	–	–	–	$115	$2,980
Allowance for bad debts	$228	$355	–	–	–
Hedge losses resulting from February power crisis in Texas	–	–	–	–	$9,133
Merger and acquisition transaction costs	$2,272	$1,949	$1,234	$675	$5,635
Settlement agreements	$900	$4,000	–	–	–
Tender-related deposits write-off	–	–	–	–	$134
Write-off of unsuccessful exploration and storage activities	$1,446	$3,930	$3,733	$828	–
Adjusted EBITDA	**$581,985**	**$550,455**	**$481,741**	**$435,463**	**$401,444**

North Valley Complex, 39MW
Geothermal + 7MW Solar, NV, USA

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, 2025

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)*
6884 Sierra Center Parkway, Reno, Nevada	**89511-2210**
(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 has filed a report on and attestation to its management's assessment of the effectiveness of its internal control over financial reporting under Section 404(b) of the Sarbanes-Oxley Act (15 U.S.C. 7262(b)) by the registered public accounting firm that prepared or issued its audit report. ☑

If securities are registered pursuant to Section 12(b) of the Act, indicate by check mark whether the financial statements of the registrant included in the filing reflect the correction of an error to previously issued financial statements. ☐

Indicate by check mark whether any of those error corrections are restatements that required a recovery analysis of incentive-based compensation received by any of the registrant's executive officers during the relevant recovery period pursuant to §240.10D-1(b). ☐

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, 2025 the aggregate market value of the registrant’s common stock held by non-affiliates was $5,086,197,847. As of February 20, 2026, the number of outstanding shares of common stock, par value $0.001 per share was 60,845,411.

Portions of the registrant's definitive proxy statement for its 2026 Annual Meeting of Stockholders are incorporated by reference into Part III of this Form 10-K.

ORMAT TECHNOLOGIES, INC.

FORM 10-K FOR THE YEAR ENDED DECEMBER 31, 2025

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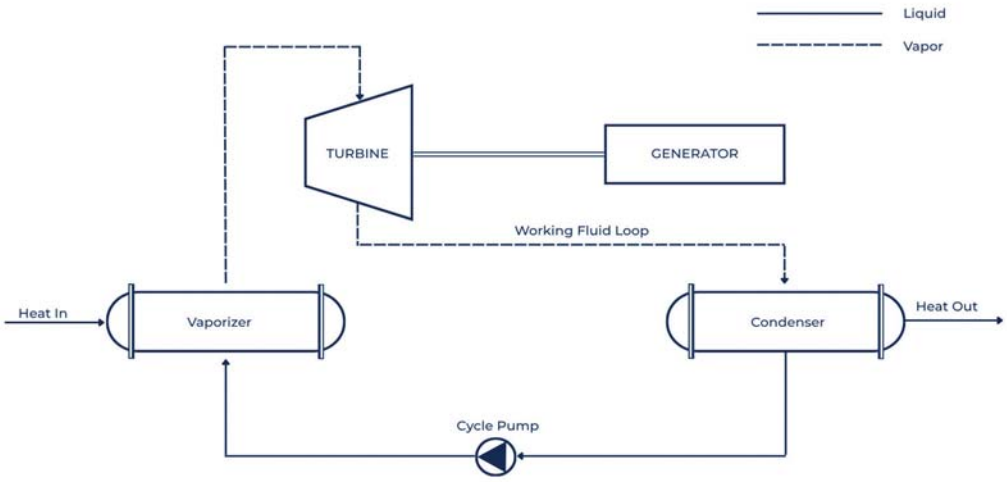
Glossary of Terms

Unless the context otherwise requires, all references in this Annual Report on Form 10-K (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 Annual Report. When the following terms and abbreviations appear in the text of this report, they have the meanings indicated below:

Term	Definition
ACC	Air-cooled Condenser
ACUA	Atlantic County Utilities Authority
AGS	Advanced Geothermal System
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
BESS	Battery Energy Storage Systems
BLM	Bureau of Land Management of the U.S. Department of the Interior
BOT	Build, operate and transfer
BPP	PLN's existing average cost of generation
CAISO	California Independent System Operator
CalGEM	California Geologic Energy Management
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 as a percentage
CARES	Coronavirus Aid, Relief, and Economic Security Act
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
CPA	Clean Power Alliance
CPI	Consumer Price Index
CPUC	California Public Utilities Commission
DEG	Deutsche Investitions-und Entwicklungsgesellschaft mbH
CREE	The Regulatory Commission of Electric Power in Honduras
DFC	U.S. International Development Finance Corporation (formerly OPIC)
DOE	U.S. Department of Energy
DOMLEC	Dominica Electricity Services Ltd.
DSCR	Debt Service Coverage Ratio

EBITDA	Earnings before interest, taxes, depreciation, amortization and accretion
EDF	Electricite de France S.A.
EGL	Eastland Generation Limited
EGS	Enhanced Geothermal Systems
EIB	European Investment Bank
Eligible Green Projects	Allocations made by the Company or any of its subsidiaries to any of the projects defined below in the 24 months prior to or 24 months following the issuance date of the bonds. Eligible Green Projects include the following (for illustrative purposes only): (i) renewable energy (new geothermal energy generation facilities with GHG emissions less than 100g CO2d/KWh; upgrades to existing geothermal energy generation facilities to increase efficiency, resiliency and reliability; energy storage systems; or solar PV systems); and (ii) eco-efficient and/or circular economy adapted products.
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
ERCOT	Electric Reliability Council of Texas, Inc.
EPRA	Energy and Petroleum Regulatory Authority of Kenya
EU	European Union
EWG	Exempt Wholesale Generators
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
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
GIS	Geographic Information Systems
Green bonds or green convertible bonds	Bonds, which the proceeds from, are used to finance and/or refinance, in whole or in part, new or on-going projects in accordance with the Ormat Green Finance Framework.
GW	Gigawatt
GWh	Gigawatt hour
HELCO	Hawaii Electric Light Company
HECO	Hawaii Electric Company
IDWR	Idaho Department of Water
IESO	The Independent Electricity System Operator.
IFM	In Front of the Meter
IGA	International Geothermal Association
IID	Imperial Irrigation District
INDE	Instituto Nacional de Electrification
IOUs	Investor-Owned Utilities

IPCC	Intergovernmental Panel on Climate Change
IPPs	Independent Power Producers
IRA	Inflation Reduction Act of 2022
ISO	Independent System Operator
ISO-NE	ISO New England
ITC	Investment Tax Credit
JBIC	Japan Bank for International Cooperation
John Hancock	John Hancock Life Insurance Company (U.S.A.)
JPM	J.P. Morgan Capital Corporation
KenGen	Kenya Electricity Generating Company Ltd.
Kenyan Energy Act	Kenyan Energy Act, 2006
KETRACO	Kenya Electricity Transmission Company Limited
KGRA	Known Geothermal Resource Area
KLP	Kapoho Land Partnership
KPLC	Kenya Power and Lighting Co. Ltd.
KRA	Kenya Revenue Authority
kW	Kilowatt - A unit of electrical power that is equal to 1,000 watts
kWh	Kilowatt hour(s), a measure of power produced
LCOE	Levelized Costs of Energy
LSE	Load Serving Entity
Mammoth Pacific	Mammoth-Pacific, L.P.
MEMR	The Indonesian Minister of Energy and Mineral Resources
MW	Megawatt - One MW is equal to 1,000 kW or one million watts
MWh	Megawatt hour(s), a measure of energy produced
NIS	New Israeli Shekel
NOA	Notice of Assessments
Notes	Convertible notes from 2022
NV Energy	NV Energy, Inc.
NYSE	New York Stock Exchange
NYISO	New York Independent System Operator, Inc
OEC	Ormat Energy Converter
OBBBA	One Big Beautiful Bill Act
Opal Geo	Opal Geo LLC
OPC	OPC LLC, a consolidated subsidiary of the Company
OrCal	OrCal Geothermal Inc., a wholly owned subsidiary of the Company
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
Ormat Green Finance Framework	A framework developed in alignment with the Green Bond Principles (2021), as published by the International Capital Markets Association, by which the proceeds of green bonds are used to finance and/or refinance, in whole or in part, one or more Eligible Green Projects.
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
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
Orzunil	Orzunil I de Electricidad, Limitada, a wholly owned subsidiary of the Company
PG&E	Pacific Gas and Electric Company
PGV	Puna Geothermal Venture, a wholly owned subsidiary of the Company
PJM	PJM Interconnection, LLC
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
PTC	Production Tax Credit
PUC	Public Utilities Commission
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

QF	Qualifying Facilities - (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)
RCEA	Redwood Coast Energy Authority
REC	Renewable Energy Credit
REG	Recovered Energy Generation
RER	Renewable Energy Resource certificate
RPS	Renewable Portfolio Standards
RTE	Round Trip Efficiency
RTO	Regional Transmission Organization
SAGE	Sage Geosystems Inc.
SCE	Southern California Edison
SCPPA	Southern California Public Power Authority
SDCP	San Diego Community Power
SDG&E	San Diego Gas and Electric
SEC	U.S. Securities and Exchange Commission
Securities Act	U.S. Securities Act of 1933, as amended
SLB	SLB (NYSE: SLB)
SOFR	Secured Overnight Financing Rate
SOL	Sarulla Operations Ltd.
Solar PV	Solar photovoltaic
SOX Act	Sarbanes-Oxley Act of 2002
SRAC	Short Run Avoided Costs
TASE	Tel Aviv Stock Exchange
Tax Act	Tax Cuts and Jobs Act
UIC	Underground Injection Control
UN	United Nations
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
VCE	Valley Clean Energy
Viridity	Viridity Energy Solutions Inc., a wholly owned subsidiary of the Company

Cautionary Note Regarding Forward-Looking Statements and Risk Factor Summary

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", "intend", "estimates", "predicts", "projects", "potential", "target", "goal", 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.

These forward-looking statements are made only as of the date hereof, and, except as legally required, we undertake no obligation to update or revise the forward-looking statements, whether as a result of new information, future events or otherwise.

A summary of the risks that may cause actual results to differ from our expectations include, but are not limited to the following:

Risks Related to the Company's Business and Operation

- Our financial performance depends on the successful operation of our geothermal, REG, solar PV power plants under the Electricity segment as well as our energy storage facilities which are subject to various operational risks.
- Our exploration, development, and operation of geothermal energy resources are subject to geological risks and uncertainties.
- 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 may not achieve its goal of enhancing shareholder value.
- Changes in U.S. and foreign government policy, including the imposition of or increases in tariffs and changes to existing trade agreements, could have a material adverse effect on global economic conditions and our business, results of operations, prospects and financial condition.
- Our investments and profitability in battery Energy Storage System (BESS) may be negatively affected by a number of factors, including increases in storage costs, expanded trade restrictions, risk of fire, volatility in merchant prices and competition.
- Our investments in EGS projects involve substantial technical, operational, and geological uncertainties, including risks related to reservoir creation and sustainability, drilling success rates, well productivity, thermal recovery, induced seismicity, permitting, and long-term system performance. There can be no assurance that EGS projects in which we invest will achieve expected technical milestones, operate reliably, or produce energy at commercially viable levels.
- Concentration of customers, specific projects and regions may expose us to heightened financial exposure.
- Our international operations expose us to risks related to the application of foreign laws and regulations.
- Political, economic and other conditions in the emerging economies where we operate, including Israel, may subject us to greater risk than in the developed U.S. economy.

- Conditions in and around Israel, where much of our senior management and our main Product segment production and manufacturing facilities are located, may adversely affect our operations, may limit our ability to produce and sell our products, and may limit our ability to support our operations.
- Some of our leases will terminate if we do not extract geothermal resources in "commercial quantities" or fail to comply with such leases or applicable law or if the lessor under any such lease defaults on any debt secured by the relevant property.
- Our business development activities may not be successful and our projects under construction or facilities undergoing enhancement and repowering may be delayed due to permitting, regulatory, interconnection and other factors.
- Our future growth depends, in part, on the successful enhancement of a number of our existing facilities.
- We rely on power transmission facilities that we do not own or control.
- Our use of joint ventures may limit our flexibility with jointly owned investments.
- Our operations could be adversely impacted by climate change and other extreme weather events.
- We could be impacted by regulatory and other responses to climate change.
- We may not be able to successfully complete acquisitions, and we may not be able to successfully integrate, or realize anticipated synergies from, companies that we have acquired and may acquire in the future.
- Competition for power purchase agreements, development sites, interconnection capacity, and skilled personnel may adversely affect our ability to grow our business or maintain favorable contract terms.
- Changes in costs and technology may significantly impact our business by making our power plants and products less competitive, resulting in our inability to sign new or recontracted PPAs for our Electricity segment and new supply and EPC contracts for our Products segment.
- Our intellectual property rights may not be adequate to protect our business.
- We may experience a cyber-incident, cyber security breach, severe natural event or physical attack on our operational networks and information technology systems.

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.
- 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.
- If any of our domestic power plants lose their 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.
- The absence of new or renewed BLM permits for solar PV projects on U.S. federal lands could impair our development activities, project pipeline and growth prospects.
- The reduction, elimination or inability to monetize government incentives and tax credits could adversely affect our business, financial condition, future results and cash flows.
- Our operations are primarily conducted through our subsidiaries, which are separate legal entities, and our ability to generate cash depends substantially on the performance of our subsidiaries and the power plants they operate, most of which are subject to restrictions and taxation on dividends and distributions.
- The costs of compliance with federal, state, local and foreign environmental laws, and our ability to obtain and maintain environmental permits and governmental approvals required for development, construction and/or operation, may result in liabilities, increased costs and delays in construction (as well as fines or penalties that may be imposed upon us in the event of non-compliance with such laws or regulations).
- 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.
- U.S. federal, state and foreign country income tax reform could adversely affect us.

- Litigation, legal proceedings, regulatory investigations or other administrative proceedings could expose us to significant liabilities and reputational damage that could have a material adverse effect on us.

Risks Related to Economic and Financial Conditions

- We may be unable to obtain the financing we need on favorable terms to pursue our growth strategy and any future financing we receive may be less favorable to us than our current financing arrangements.
- We have incurred substantial indebtedness that may decrease our business flexibility, access to capital, and/or increase our borrowing costs, and we may still incur substantially more debt, which may adversely affect our operations and financial results.
- Our debt obligations may adversely affect our ability to raise additional capital and will be a burden on our future cash resources, particularly if we elect to settle these obligations in cash upon conversion or upon maturity or required repurchase.
- 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.
- If our project subsidiaries default on their obligations under such debt or lease financing arrangements, we may be required to make payments to the relevant debt holders, and if the collateral is foreclosed upon, we may lose certain of our power plants.
- We may experience fluctuations in the costs of construction, raw materials, commodities, and drilling.
- Our commodity derivative activity may limit potential gains, increase potential losses, result in earnings volatility and involve other risks.
- We are exposed to various credit risks.
- We may not be able to obtain sufficient insurance coverage to cover damages to our assets and profitability.

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.
- Threats of terrorism may impact our operations in unpredictable ways and could adversely affect our business, financial condition, future results and cash flow.

Risks Related to Ownership of our Common Stock

- Future equity issuances, including through our current or any future equity compensation plans, could result in dilution, which could cause the price of our shares of common stock to decline.
- The price of our common stock has in the past and may in the future fluctuate substantially, and your investment may decline in value.

Market and Industry Data

This Annual Report includes market and industry data and forecasts that we have derived from publicly available information, various industry publications, other published industry sources and internal data and estimates. Industry publications and other published industry sources generally indicate that the information contained therein was obtained from sources believed to be reliable. Internal data and estimates are based upon information obtained from trade and business organizations and other contacts in the markets in which we operate and our management's understanding of industry conditions. Any estimates underlying such market-derived information and other factors could cause actual results to differ materially from those expressed in the independent parties' estimates and in our estimates.

Company Contact and Sources of Information

Our website is www.ormat.com. Information contained on or accessible via our website, including our Sustainability Report, is not part of or otherwise incorporated by reference into this Annual Report. Information that we furnish to or file with the U.S. Securities and Exchange Commission (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 made available for download, free of charge, through our website as soon as reasonably practicable. Our SEC filings, including exhibits filed therewith, are also available directly on the SEC's website at www.sec.gov.

We may use our website as a distribution channel of material Company information. Financial and other important information regarding the Company is routinely posted on and accessible through our website at www.ormat.com.

Accordingly, investors should monitor this channel, in addition to following our press releases, SEC filings and public conference calls and webcasts.

PART I

ITEM 1. BUSINESS

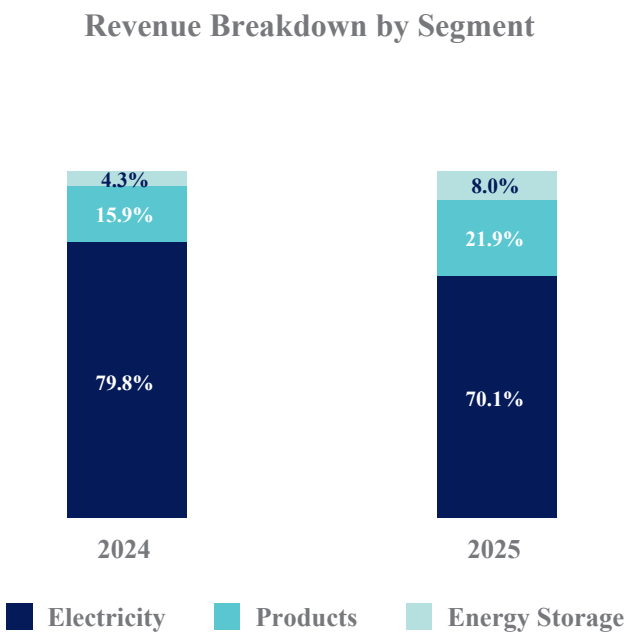
Overview

We are a leading vertically integrated company primarily engaged in the geothermal power business. We leverage our core capabilities, proprietary technologies, and global presence to expand our activities in conventional geothermal development, recovered energy generation and emerging geothermal technologies, including piloting of new EGS technologies. In addition, we are expanding into different complementary energy solutions, including stand alone utility scale energy storage services and solar PV generation (including hybrid geothermal and solar PV as well as solar plus energy storage). Our objective is to become a leading global provider of renewable energy and to help mitigate climate change by providing reliable base-load and flexible alternatives to carbon-intensive energy sources. To support this objective, we have adopted a strategic plan focused on several key initiatives to expand our business, including advancing EGS through collaborations and pilot projects, diversifying our renewable energy offerings, and leveraging our operational expertise to drive long-term growth.

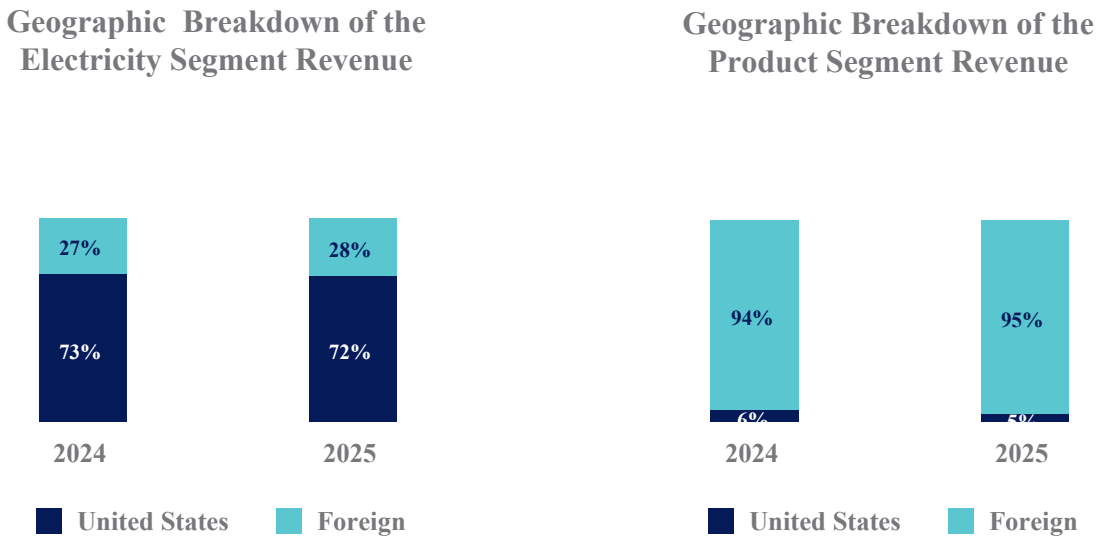
We currently conduct our business activities in three business segments:

- *Electricity Segment.* In the Electricity segment, 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. Since the beginning of 2025, we have increased our commercial operation by 115MW from geothermal and solar PV power plants, achieved through both organic growth and M&A. Through organic development, 6MW were contributed by the repowering of the Beowawe geothermal plant, 17MW, our proportional share, by the Ijen geothermal facility in Indonesia, and 42MW by the Arrowleaf solar PV plant, which is connected to an energy storage system. Furthermore, we acquired an additional 20MW from the Blue Mountain geothermal plant after closing a transaction with Cyrq Energy in June 2025 and another 30MW from a solar PV plant connected to a battery energy storage system in Hawaii, purchased from Innergex Renewable Energy Inc. in January 2026.
- *Product Segment.* In the Product segment, we design, manufacture and sell equipment for geothermal and recovered energy-based electricity generation and provide services relating to the engineering, procurement and construction of geothermal and recovered energy-based power plants. During 2025, we signed new contracts that were added to our backlog, and secured $103.5 million of anticipated Product revenues, the majority of which we expect to be recognized over the next two years. In addition, in January 2026 we added approximately $100.0 million to the backlog related to the TOPP2 project in New Zealand that was transferred to third party at COD and which we expect to be recorded as revenues in the first quarter of 2026.
- *Energy Storage* Segment. In the Energy Storage segment, we own and operate grid-connected, stand alone In Front of the Meter (IFM) BESS facilities, which provide capacity, energy and ancillary services directly to the electric grid. We operate our facilities in three main areas in the U.S., California, Texas and the East Coast (mainly in the PJM market) and generate our revenues mainly from the sale of ancillary services in the merchant market and /or tolling agreements and RA contracts. Since the beginning of 2025, we commissioned two energy storage facilities with a total capacity of 95MW/260 MWh, one in Texas and the second that is connected to the Solar PV power plant in California. In addition, we acquired a 30MW/120MWh battery energy storage system connected to a solar PV power plant in Hawaii from Innergex Renewable Energy Inc, in January 2026.

The following chart sets forth a breakdown of our revenues for each of the years ended December 31, 2025 and 2024:



The following chart sets forth the geographical breakdown of revenues attributable to our Electricity and Product segments for each of the years ended December 31, 2025 and 2024:



The revenues attributable to our Energy Storage segment for each of the years ended December 31, 2025 and 2024 were 100% generated in the United States.

Our Electricity Segment

Our Company-owned power plants include both power plants that we have built and acquired. The substantial majority of these power plants 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, geothermal energy 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 contributes significantly less to negative climate change and local and regional incidences of acid rain than energy produced by burning fossil fuels. Additionally, unlike wind or solar power plants, geothermal power plants can generally operate 24 hours a day, therefore providing 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.

We own and operate geothermal and solar PV hybrid projects, solar PV plus storage facilities and standalone solar PV power plants with similar projects currently under construction. In our hybrid projects, electricity generated from the solar PV power plant is used to offset the equipment's energy use at the geothermal facility, increasing the net geothermal energy delivered to the grid. Our standalone solar PV power plants sell their output under long term PPAs.

We also construct, own, and operate 50MW of recovered energy-based power plants. Recovered energy is derived from residual heat generated as a by-product of gas turbine-driven compressor stations, solar thermal units and industrial processes such as cement manufacturing. This heat, which would otherwise be wasted, is captured and used to generate electricity without burning additional fuel or producing additional emissions.

Our geothermal power plants sell substantially all of their output under long-term PPAs, most with fixed prices, denominated in or linked to the U.S. dollar or Euro. As of December 31, 2025, these contracts had a weighted average remaining term of approximately 14 years based on contributions to segment revenue. The counterparties to our PPAs in the United States have a credit rating of between Baa1 to Ba2 (stable) by Moody's and AA+ to B+ by S&P. The purchasers of electricity from our foreign power plants are primarily state-owned entities in countries with below investment grade ratings.

Power Plants in Operation

We own and operate 35 power plants and complexes globally, with an aggregate generating capacity of 1,340MW, comprising geothermal, REG and solar facilities as listed below. Geothermal represents 81.3% of our Electricity Segment generating capacity. In 2025, our geothermal and REG power plants achieved capacity factors of 84% and 70%, respectively, significantly exceeding the 20%-30% capacity factors typical of wind and solar projects.

The table below summarizes certain key non-financial information relating to our power plants and complexes as of February 25, 2026. Generating capacity figures have been updated from our 2024 disclosure to reflect changes in resource temperature and other factors that impact resource capabilities:

Type	Region	Plant	Ownership[1]	Generating capacity (MW)[2]	PPA Tenure	Capacity Factor[3]
Geothermal	California	Ormesa Complex	100%	40	17	86%
		Heber Complex	100%	91	17	
		Mammoth Complex	100%	65	13	
		Brawley	100%	3 [4]	6	
	West Nevada	Steamboat Complex [5]	100%	79	21	81%
		Brady Complex[5]	100%	24	23	
	East Nevada	Tuscarora	100%	17	8	88%
		Jersey Valley	100%	8	7	
		McGinness Hills	100%	141[4]	13	
		Don A. Campbell	100%	28	9	
		Tungsten Mountain [5]	100%	41	18	
		Dixie Valley	100%	64	13	
		Blue Mountain[7]	100%	22	4	
		Beowawe[5]	100%	20	28	
	North West Region	Neal Hot Springs	60%	22	12	74%
		Raft River	100%	12	8	
		San Emidio[6],[5]	100%	39	18	
		Still Water Complex[5]	100%	14	4	
		Salt Wells	100%	10	25	
	Hawaii	Puna	63.3%	38	27	63%

Type	Region	Plant	Ownership[1]	Generating capacity (MW)[2]	PPA Tenure	Capacity Factor[3]
	Utah	Cove Fort	100.0%	18	8	90%
	International	Amatitlan (Guatemala)	100%	20	3	
		Zunil (Guatemala)	97%	20	9	
		Olkaria III Complex (Kenya)	100%	150	9	84%
		Bouillante (Guadeloupe, France)	63.75%	15	5	
		Platanares (Honduras)	100%	30	7	
Total Consolidated Geothermal				1,031		84%
REG [8]		OREG 1	100.0%	22	6	
		OREG 2	100.0%	22	9	
		OREG 3	100.0%	5.5	5	
Total REG				50		70%
Solar		Tungsten Mountain	100%	12	NA	
		Wister	100%	20	17	
		Steamboat Solar	100%	17	NA	
		Stillwater Solar PV	100%	20	NA	
		Stillwater Solar PV II	100%	20	0	
		Woods Hill	100%	20	13	
		North Valley	100%	7	NA	
		Beowawe	100%	6	NA	
		Arrowleaf[10]	100%	42	20	
		Brady	100%	6	NA	
		Hoku[11]	100%	30	25	
Total Solar				200		
Unconsolidated Geothermal	Indonesia	Sarulla Complex	12.75%	42	22	
	Indonesia	Ijen[9]	49%	17	30	
Total Unconsolidated Geothermal				59		
Total [12]				**1,340**		

1. We have a controlling interest in and we operate all of our power plants, except for Sarulla and Ijen both in Indonesia. In the U.S., certain other financial institutions hold equity interests in seven of our subsidiaries: (i) ORNI 41, which owns the McGinness Hills Phase 3 located in Nevada; (ii) ORNI 43, which owns the Tungsten Mountain geothermal power plant located in Nevada; (iii) Steamboat Hills, LLC, which owns the Steamboat Hills power plant located in Nevada; (iv) CD4 partnership that owns the CD4 power plant, under Mammoth Complex, in California; (v) ORNI 36, which owns the North Valley power plant, under San Emidio complex, located in Nevada, (vi) Heber Geothermal Company, LLC and OrHeber2, LLC, which own the Heber 1 and Heber 2 geothermal power plants located in California, respectively; and (vii) Vessi 38, LLC and ORNI 30, LLC, which own Lower Rio energy storage facility located in Texas and Arrowleaf solar plus energy storage facility located in

California, respectively. 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 8 — “Financial Statements and Supplementary Data" under Note 12.

We own a 63.75% equity interest in the Bouillante power plant, a 97% equity interest in the Zunil power plant, a 60% equity interest in the Neal Hot Spring power plant, and a 63.25% direct equity interest in the Puna plant. We list 100% of the generating capacity of the Bouillante power plant, the Zunil power plant, the Neal Hot Springs power plant and the Puna power plant in the table above because we control their operations. We list our 12.75% share of the generating capacity of the Sarulla complex and 49% of the generating capacity of the Ijen power plant as we own minority interests in these projects. Revenues from the Sarulla complex and from the Ijen power plant are not consolidated and are presented under “Equity in earnings (losses) of investees, net” in our consolidated 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. Capacity factor is generally calculated as the actual MWh generation divided by the maximum potential generation (generating capacity multiplied by 8,760 hours). In the case of curtailments by the grid operator the generated MWh are taken into account in our calculation although the curtailed MWh were not sold to the grid.
4. Generating capacity reduced to reflect cooling experienced in the resource.
5. This is a hybrid geothermal and solar power plant that uses the solar energy for geothermal power plant auxiliary power. The solar PV facilities are presented separately in the table above.
6. The San Emidio complex includes 25MW from North Valley that commenced commercial operation in May 2023.
7. The Blue Mountain power plant was acquired and added to our portfolio in June 2025. The Power plant generating capacity increased due to better performance than expected.
8. The OREG power plants are not operating at full capacity due to low run time of the compressor stations that serve as the power plants heat source. This has resulted in lower power generation. During the fourth quarter of 2025, the company deemed that one of its customers is expected to terminate the waste heat agreement related to the OREG 2 facility.
9. The 35MW Ijen power plant in Indonesia commenced operation in February 2025. Our share is 17MW (49%).
10. The Arrowleaf solar PV plus energy storage facility commenced operation in December 2025. The solar PV generating capacity, attached to the storage facility, is included in the Electricity segment portfolio, however, 100% of the revenue is recorded under the Energy Storage segment.
11. The Hoku solar PV plus energy storage facility in Hawaii was acquired in January 2026 from Innergex Renewable Energy Inc. The solar PV generating capacity, attached to the storage facility, is included in the Electricity segment portfolio, however, 100% of the revenue is recorded under the Energy Storage segment.
12. The total Electricity segment portfolio presented in the table above is as of February 25, 2026. The total Electricity segment portfolio as of December 31, 2025 stood at 1,310MW.

New Power Plants

We are currently constructing new power plants and expanding existing facilities. We have released for construction geothermal and solar PV projects with generating capacity of **136.5**MW worldwide. In addition, we disclosed 24MW of geothermal and solar PV projects in various stages of development in the United States.

We hold substantial land positions across **34** prospects in the United States and **16** prospects internationally (Ethiopia, Guatemala, Honduras, Indonesia and New Zealand) that we expect will support future geothermal development. These positions consist of leases, geothermal exploration concessions, and lease options. We have commenced or plan to start exploration activity on many of these prospects.

We expect to add 310MW to 410MW of generating capacity in the Electricity Segment, reaching a total capacity of 1.65 to 1.75 GW by 2028.

Our Product Segment

We design, manufacture and sell electricity generation products and provide related services as described below. We also provide cementing services for well drilling to third parties. We primarily manufacture products to fulfill customer orders, though we also produce inventory for future projects, whether owned by us or by third parties.

Power Units for Geothermal Power Plants

We design, manufacture and sell power units for geothermal electricity generation, referred to as OECs. Our customers include contractors, developers, owners and operators of geothermal power plants.

We also support EGS, which enable geothermal power generation in areas lacking sufficient natural underground reservoirs. This technology has the potential to expand the geographic reach of geothermal energy while maintaining its renewable characteristics. Our OECs are engineered to operate effectively under EGS conditions.

Power Units for Recovered Energy-Based Power Generation

We design, manufacture and sell power units that generate electricity from recovered energy, commonly known as "waste heat." Our customers include owners and operators of interstate natural gas pipelines, gas processing plants, cement plants and other energy-intensive industrial facilities.

EPC of Power Plants

We provide turnkey EPC services for geothermal and recovered energy power plants using power units we design and manufacture. Our customers include geothermal power plant owners and operators of energy-intensive industrial facilities.

Production Pumps

We design, manufacture and sell geothermal production pumps to third-party power plant operators and have identified geothermal district heating as a potential market.

Our Energy Storage Segment

Our Energy Storage segment has grown consistently since 2019 and remains a strategic priority for investment and expansion.

We own and operate 19 BESS projects in the U.S. with an aggregate capacity of 415MW/1,038MWh. The following table summarizes key information regarding these projects as of February 25, 2026:

Project Name	Customer	Location	Size (MW)	MWh	Type of contract
ACUA	PJM	NJ	1	1	Merchant
Plumsted	PJM	NJ	20	20	Merchant
Stryker	PJM	NJ	20	20	Merchant
Hinesburg	ISONE	VT	2	5	Merchant
Rabbit Hill	ERCOT	TX	10	10	Merchant
Pomona	SCE/CAISO	CA	20	80	Capacity contract and merchant
Vallecito	SCE/CAISO	CA	10	40	Capacity contract and merchant
Tierra Buena	RCEA/VCE/ CAISO	CA	5	20	Capacity contract and merchant
Upton	ERCOT	TX	23	23	Merchant
Andover	PJM	NJ	20	20	Merchant
Howell	PJM	NJ	7	7	Merchant
Bowling Green	BGMU/PJM	OH	12	12	Capacity contract and merchant
Pomona 2	SCE/CAISO	CA	20	40	Full tolling
East Flemington	PJM	NJ	20	20	Merchant
Bottleneck	SDG&E	CA	80	320	Full tolling
Montague	PJM	NJ	20	20	Merchant
Lower Rio	ERCOT	TX	60	120	Merchant
Arrowleaf	SDCP	CA	35	140	Full tolling
Hoku	HECO	HI	30	120	PPA
Total			**415**	**1,038**	

New BESS Projects

We are constructing 8 additional energy storage projects with a total capacity of 410MW/1,540MWh in California, Texas and Israel. In addition, we have an approximately 2.7GW/10.0GWh pipeline of potential projects in various stages of development across the United States, supporting our target of 950–1,050MW/2,500–2,900MWh of energy storage capacity by year-end 2028. We plan to continue leveraging our project development and finance experience, EPC expertise, and utility relationships to develop additional BESS projects.

Business Strategy

Our strategy focuses on developing a geographically balanced portfolio of geothermal, energy storage, and solar PV while strengthening our leadership in geothermal energy to become a leading global renewable energy provider.

In this evolving market, our strategy is to build on our existing capabilities and core competencies while expanding our ability to compete in next-generation geothermal markets, including enhanced geothermal systems ("EGS") and other advanced solutions. These technologies have the potential to increase the scale of geothermal power plants, broaden geographic applicability, and expand the addressable market for firm, renewable power.

We plan to pursue next-generation geothermal opportunities through a disciplined approach that leverages our established geothermal expertise. We intend to collaborate selectively with industry-leading drilling and subsurface service providers and engage with emerging EGS and advanced geothermal technology companies to enhance execution capabilities, shorten time to market, and reduce technical and commercial risks. This approach positions us to deliver scalable, reliable geothermal solutions while maintaining capital discipline, execution certainty, and sustainable cash flow generation.

Business Goals

Our goals include continuing our leading position in the geothermal energy market and becoming a leading global provider of renewable energy. Our strategy focuses on four main elements:

- Developing our low carbon renewable geothermal business in the United States and globally;

- Growing our market position in the IFM energy storage market;
- Pursuing our core capabilities and to lead the next-generation geothermal market; and
- Pursuing synergistic and environmentally responsible growth by leveraging our core competencies, strong market reputation, and new market opportunities across the renewable energy sector.

We intend to implement this strategy through the following initiatives:

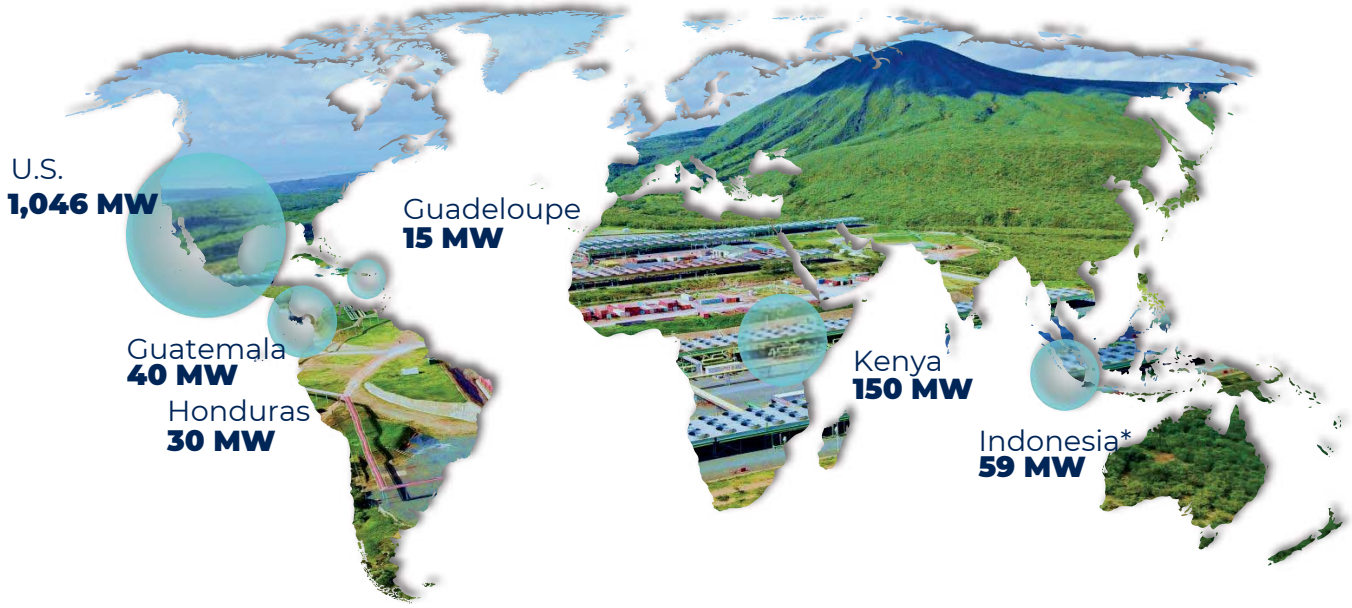
- *Development and Construction of New Geothermal Power Plants* — We intend to identify commercially viable geothermal resources and expand exploration drilling to accelerate development and construction of zero-emission geothermal power plants. We expect to continue entering into long-term PPAs that provide stable cash flows and support long-term value creation.
- *Expanding our Geographical Reach* — We plan to increase business development activities to grow our global footprint across all segments.
- *Accelerating Development and Construction of New Energy Storage Assets* — We intend to increase business development efforts to identify sites and advance construction of energy storage facilities, including hybrid storage and solar PV facilities. Our goal is to grow our energy storage portfolio with grid-supporting solutions that balance long-term contracted revenues (including tolling agreements) with selective merchant exposure.
- *Acquisition of Geothermal Assets* — We intend to accelerate growth through strategic global acquisitions, including geothermal assets and operating or development-stage assets that support our geothermal business, enhance scale, and strengthen long-term value creation.
- *Acquisition of Energy Storage Projects and Solar plus Storage Assets* — We intend to accelerate growth through acquisitions of operating assets, shovel-ready projects, and projects in various development stages, applying disciplined evaluation criteria for returns, risk allocation, permitting progress, and contract quality.
- *Increasing Output from Existing Geothermal Power Plants* — We plan to increase output from existing plants by adding generating capacity, upgrading technology, drilling new or redrilling existing wells, and improving reservoir management, including heat source supply and delivery methods.
- *Diversifying Our Customer Base* — At our Electricity segment we plan to evaluate strategies to expand our customer base, including in-front-of-the-meter opportunities with hyperscalers, data centers developers and operators, corporations, and CCA markets. In the near term, we expect the majority of Electricity Segment revenues to continue coming from traditional utility customers.
- *Maintaining a Prudent and Flexible Capital Structure* — We seek to maintain a prudent, flexible capital structure supported by multiple financing sources, including non-recourse and recourse project financings, bonds (including green bonds), corporate bank debt, sales of differential membership interests and equity interests in subsidiaries, tax credit transfers, revolving credit facilities and term loans. Our cash flow profile, long-term contracts, and capital-raising ability provide flexibility to optimize our capital structure over time.
- *Improving Our Technological Capabilities* — We intend to continue investing in renewable energy R&D, leveraging our expertise to improve power plant components, reduce O&M costs, develop competitive low-carbon generation products, and pursue new service opportunities. We are expanding our geothermal competencies to provide high-efficiency solutions for high-enthalpy applications using our binary enhanced cycle technology.
- *Manufacturing and Providing Products and EPC Services* — We intend to continue designing, manufacturing and contracting power plants for our own use and selling power units and other generation equipment for geothermal and recovered energy-based electricity generation.
- *Expanding into Next-Generation Geothermal (Including EGS)* — We are working to leverage our core geothermal expertise to develop and deploy next-generation geothermal solutions across both our Product and Electricity segments, including EGS. This includes advancing internal R&D, and building on existing pilot initiatives, including our collaboration with SLB and Sage, while selectively developing capabilities internally or with third parties to address technical gaps and unlock new market opportunities aligned with our strategic plan.
- *Expanding into New Technologies Across Renewable Energy Platforms*— We intend to leverage our technological capabilities across multiple renewable energy platforms, including, solar power generation and

energy storage. We aim to support continuous innovation through research and development efforts designed to enhance efficiency, reliability, and long-term performance.

The map below shows our worldwide portfolio of operating geothermal, solar PV and recovered energy power plants as of February 25, 2026.

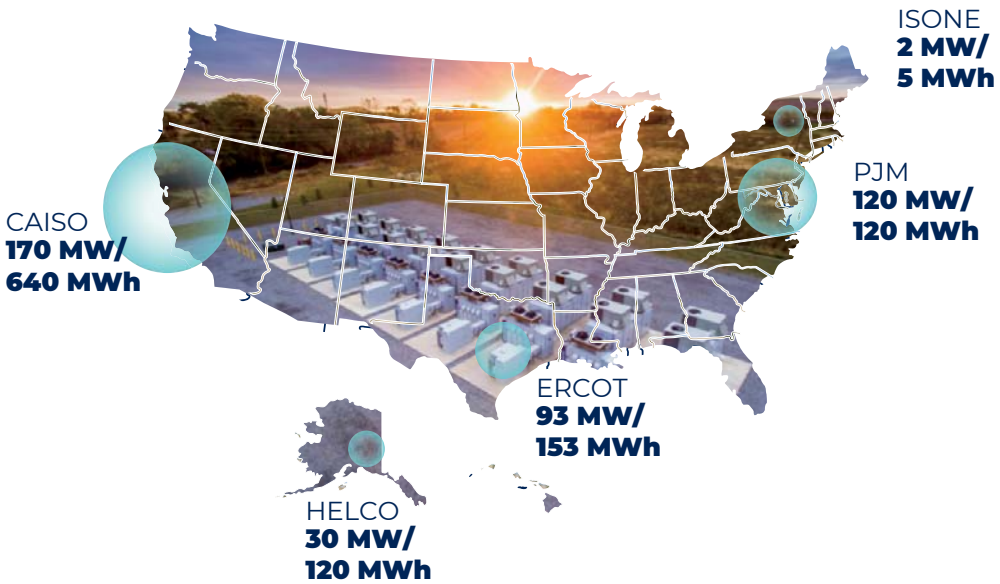
*In Indonesia, in the Sarulla complex and in Ijen power plant we include our 12.75% and 49% share only, respectively.

Global Electricity Segment Portfolio 1,340 MW



The map below shows our portfolio of operating storage facilities as of February 25, 2026.

Energy Storage portfolio (415 MW / 1,038 MWh)



Sustainability Strategy

We are committed to engaging with stakeholders on sustainability matters and to continue strengthening our sustainability practices. We participate in and support external initiatives and collaborate with national and international associations that we believe promote alignment with our sustainability priorities, particularly with respect to geothermal energy, health and safety, and human rights. We also seek to provide timely, credible and comparable information to sustainability rating agencies and to engage with institutional investors and investor advocacy organizations on sustainability-related matters.

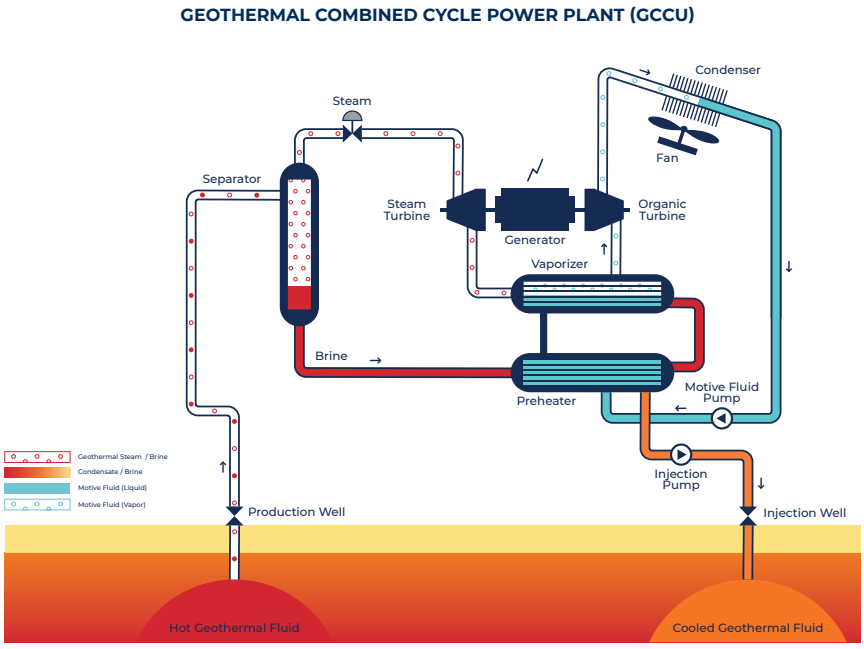
As a provider of renewable energy solutions, we monitor climate-related risks and opportunities and pursue initiatives to reduce our GHG emissions and improve energy efficiency across our operations. In addition to complying with applicable regulatory requirements, we report our annual GHG emissions to organizations such as the Carbon Disclosure Project and the Israeli Ministry of Environmental Protection's voluntary business reporting initiative.

We report annually on our progress toward environmental goals and commitments in our sustainability reports, including measures related to climate change mitigation, biodiversity conservation and water management. Our most recent Sustainability Report is available, free of charge, on our website at https://www.ormat.com/en/sustainability/report/documents/. The contents of our website, including our sustainability reports, are not part of, and are not incorporated by reference into, this Form 10-K.

Our Proprietary Technology

Our proprietary technology involves original designs of Organic Rankine Cycles including equipment such as turbines, pumps, and heat exchangers, as well as formulation of organic motive fluids (all of which are non-ozone-depleting substances). Such equipment can 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.

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, that we have deployed in previous years, is depicted in the diagram below.

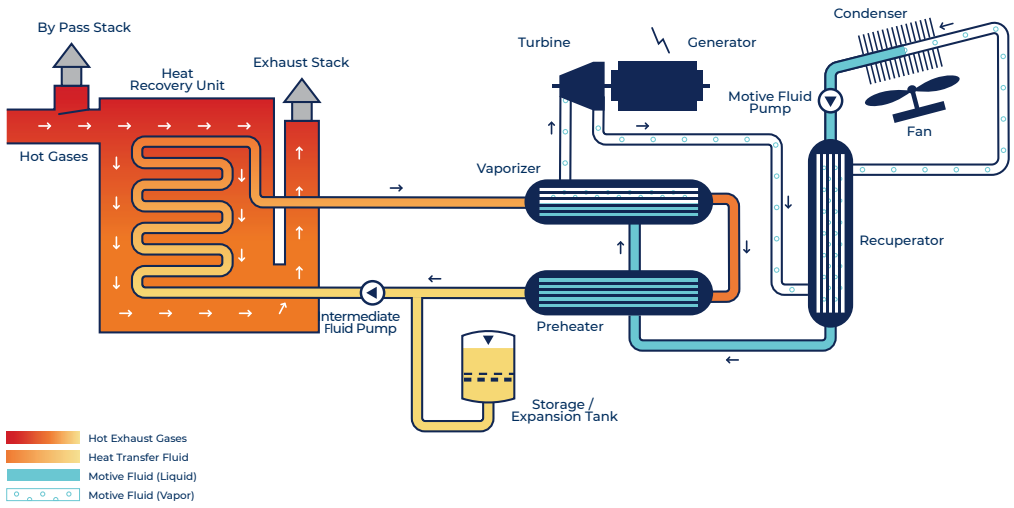


In the conversion of geothermal energy into electricity, our technology has several advantages over conventional geothermal steam turbine plants. A conventional geothermal steam turbine plant consumes significant quantities of water, causing depletion of the aquifer and requiring cooling water treatment with chemicals and consequently a need for the disposal of such chemicals. A conventional geothermal steam turbine plant also creates a 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 minimal 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 blades and the geothermal fluids, which can often be very erosive and corrosive. Instead, the geothermal fluids pass through heat exchangers, which are 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 December 31, 2025, we had 182 active patents and patent applications worldwide, including 52 patents issued in the U.S. and 12 pending patent applications worldwide. 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, pumps, heat exchangers, air coolers, seals and controls as well as geothermal production well pumps. The system-related patents cover not only particular components but also the overall energy conversion system from the "fuel supply" (e.g., geothermal fluid, waste heat, biomass or solar) to electricity production.

The system-related patents 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. 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 and brine production pumps.

As part of our continuous cost reduction and performance enhancement, we developed and patented the extraction ORC, extraction and injection turbines that allow bleed or injection of motive fluid between stages from or to the organic turbine. As the ACC is a significant piece of equipment involved in the ORC process, we focus our efforts on improving ACC performance and reduce its cost, such as the wind guiding vanes for wind effects mitigation, inclined ACC and tubes geometry variation.

We also devote resources to research and development for our Energy Storage segment. Our engineering and R&D teams are working to optimize the dispatch strategy of a BESS, develop and deploy capabilities to self-integrate BESS and test different battery cell and inverter technologies under simulated operating criteria of various energy markets to allow us to bring to market cost-effective BESS more rapidly and more optimized to the specific use cases and target revenue streams. Additionally, we hold patents in other energy storage solutions, including a mechanical energy storage system, which is currently under design and feasibility examination. A preliminary trial of this system in a small-scale unit was performed, and testing remains ongoing. Initial results obtained high RTE values compared to other mechanical energy storage solutions.

We continue to evaluate investment opportunities in companies with innovative technology or product offerings for renewable energy and energy storage solutions.

Ormat New Ventures

Ormat New Ventures is the Company's strategic corporate venture capital platform. It was established to support Ormat's long-term growth strategy by investing in early-stage energy and climate technology companies whose innovations may complement the Company's core businesses and contribute to future development opportunities.

The investment strategy focuses primarily on hardware- and systems-based technologies that can be integrated into operating energy infrastructure or enable the development of new projects. Areas of interest include advanced geothermal technologies, energy storage solutions, renewable and waste heat recovery technologies (including industrial-scale heat pumps, heat engines and other clean power generation solutions), and nuclear fission small modular reactor ("SMR") deployment technologies.

As a strategic investor, Ormat New Ventures seeks to provide portfolio companies with access to the Company's technical expertise, project development capabilities and operational experience, in addition to capital. This approach is intended to support the advancement of technologies toward commercial deployment while enabling the Company to evaluate potential applications that may enhance future projects and operating assets or being key to new markets.

Ormat New Ventures maintains an evergreen investment structure, providing flexibility in the timing and size of investments based on strategic alignment and potential impact.

As of the date of this Annual Report, the portfolio includes investments in the following companies:

- *Sage Geosystems* – Geo-pressurized geothermal technology designed for power generation, long-duration energy storage or district heating from low-permeability formations.
- *LAVA* – Isothermal thermodynamic cycle technology for heat-to-power conversion applications.
- *TerraWave* – Millimeter-wave drilling technology intended to enable access to deep and super hot geothermal resources.
- *RepAir Carbon* – Electrochemical carbon capture technology for industrial low concentration and direct air capture applications.

- *Novocycle* – Lithium-ion battery recycling technology focused on pre-treatment stage innovation to achieve higher content of material recovery.

Market Opportunities

Geothermal Market Opportunities

Renewable energy provides a long-term solution to multiple global energy challenges, including climate change, grid reliability concerns, and exposure to volatile fossil fuel commodity prices. As a result, many countries are prioritizing the development of clean, decarbonized, and dispatchable baseload renewable generation, with increasing interest in geothermal energy.

At the end of 2025, the total installed geothermal power generation capacity stood at 17,144 MW, an increase of 271 MW in 2025. The United States, Indonesia, the Philippines, Turkey, Kenya and New Zealand are the leading countries in geothermal power generation.

Governments around the world have recognized the need to diversify energy supply and reduce greenhouse gas emissions. In response, many jurisdictions have adopted, or are in the process of adopting, regulatory frameworks and policy mechanisms intended to support the deployment of low-carbon generation resources and achieve emissions reduction targets.

United States

Federal

Interest in geothermal energy in the United States continues to grow, supported by legislative and regulatory activity at the local, state, and federal levels. Policymakers and regulators increasingly recognize the ability of geothermal generation to provide reliable, non-intermittent renewable power and support grid reliability objectives. In January 2025, President Trump issued multiple Executive Orders focused on energy policy, including declaring a national energy emergency and seeking to increase domestic energy production, including geothermal energy.

At the federal level, the BLM recently adopted a new categorical exclusion for geothermal resource confirmation activities on federal geothermal leases, which is expected to reduce permitting burdens and facilitate development on public lands. In addition, the current federal administration declared an energy emergency in 2025, allowing for alternative NEPA procedures to be implemented to process energy development applications on federal lands. Both permitting authorities were utilized by BLM in 2025 for geothermal projects, expediting permitting timelines for resource confirmation activities and certain development projects. Federal approvals for administrative permits, including geothermal drilling permits, are also being processed in a timely manner, which may support increased drilling activity on federal lands.

On July 4, 2025, the OBBBA was enacted into law in the United States, replacing the IRA. The law seeks to limit content from foreign entities of concern ("FEOC") used in energy related projects that start construction after December 31, 2025. For more information, see Note 16 in the consolidated financial statements contained in this annual report.

Other Drivers of Renewable Energy Demand in the U.S.

Demand for renewable energy in the United States continues to be supported by several structural trends, including expected growth in electricity consumption from data centers, corporate decarbonization objectives, and increased electrification across multiple end-use sectors. Data centers are significant energy consumers, and as companies strive to cut emissions and boost sustainability, they are securing renewable energy through PPAs to meet carbon-free targets. In addition, broader electrification trends in transportation and industrial processes may increase overall electricity demand and support the need for additional renewable generation resources.

Increased PPA Prices in the U.S.

Increased demand for renewable power, direct demand from hyper-scalers and constrained availability of firm, dispatchable generation in certain markets have contributed to higher PPA prices. The gap between electricity supply and demand in parts of the U.S. has driven higher energy and capacity pricing. Ormat has signed several PPAs for new capacity

and for existing capacity renewal across its U.S. geothermal fleet at prices above $100 per MWh, compared to PPAs executed at levels generally between $60 per MWh and $80 per MWh during the prior five years.

State legislation and Incentives

Geothermal power is currently generated in several U.S. states, including California, Nevada, Hawaii, Idaho, Oregon, and Utah. Ormat believes there are opportunities to expand geothermal development in additional western states, including New Mexico and Colorado. New Mexico recently passed legislation increasing renewable energy requirements for investor-owned utilities to 100% by 2045, and Colorado's Energy and Carbon Management Commission recently adopted streamlined geothermal permitting regulations.

Many states have implemented a RPS programs requiring utilities to incorporate renewable energy into their generation portfolios over defined compliance periods. Renewable energy generation under these programs is typically tracked through RECs, which are used by load-serving entities to demonstrate compliance with applicable RPS requirements.

Currently, 30 states plus the District of Colombia and two U.S. territories have enacted an RPS, renewable portfolio goals, or similar laws or incentives (including clean energy standards or goals) requiring or encouraging load-serving entities to procure a specified percentage of electricity from renewable energy or recovered heat sources. Additionally, three states and one territory have voluntary renewable energy goals. A significant portion of Ormat's geothermal projects are located in California, Nevada, and Hawaii, which have among the most stringent RPS programs in the country. Ormat sees the impact of RPS and climate legislation as a significant driver to expanding existing power plants and building new renewable projects.

Certain states also offer incentives supporting geothermal energy development. For example, Nevada provides a property tax abatement of up to 55% for qualifying property used to generate geothermal electricity potentially for up to twenty years if certain job creation requirements are met. Colorado added new incentive programs beginning in 2024, including grant programs and investment and production tax credits and added additional programs in 2025 intended to continue incentivizing development of long-lead-time resources. Idaho, exempts geothermal energy producers from property tax and instead impose a 3% tax on gross energy earnings. California provides grants and loans through the California Energy Commission to promote the development of geothermal resources and technologies. In addition, the CPUC has required load-serving entities to procure significant amounts of new clean electricity, including procurement requirements for firm and dispatchable resources with high capacity factors and low on-site emissions. With its high capacity factor and ability to provide firm and flexible generation, geothermal energy may support compliance with these requirements and serve as a replacement for certain retiring baseload generation resources.

Global

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

We believe several global climate-related initiatives are likely to create business expansion opportunities for us and support the global growth of the renewable sector. Although in January 2025 President Trump signed an Executive Order to withdraw the United States from the Paris Agreement, it was initially adopted by the Twenty-first Conference of the Parties to the United Nations (UN) Framework Convention on Climate Change (2015) and subsequent UN Climate Change Conferences have reaffirmed the commitments of the Paris Agreement.

Outside of the U.S., the majority of power-generating capacity has historically been owned and controlled by governments. Since the early 1990s, however, many foreign governments have privatized their power generation industries through sales to third parties encouraging new capacity development and/or refurbishment of existing assets by independent power developers.

Latin America

Several Latin American countries have renewable energy programs and have pursued development in the geothermal market.

In Guatemala, where our Zunil and Amatitlan power plants are located, the Guatemalan government's Energy Policy 2013-2027 aims for 80% renewable energy by 2027 to ensure competitive electricity prices. Recent years have shown spot prices rising over 20% annually. With no major new generation investments expected, high prices may persist until at least 2032-2034. Despite recent volatility, market conditions are expected to stabilize later in the year.

In Honduras, where we operate our Platanares power plant, the government set a target to reach at least 80% renewable energy production by 2034. State utility ENEE is seeking up to 1,500 MW of firm capacity through large tenders.

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 plants and products to our New Zealand customers and cooperate with other potential customers for adding geothermal power generation capacity within the coming years. In 2023, we signed an EPC contract to build the Ngatamariki 58MW geothermal power plant following the 59MW Tehuka 3 geothermal project contract signed in 2022. In 2024 we signed an EPC contract to build the Te-Mihi 2A 101MW geothermal power plant, and in 2025 we built the 58MW Ngatamariki and the 50MW TOPP2 plants. The 59 MW Te Huka Unit 3 geothermal power plant achieved commercial operation in June 2025 and the 50MW TOPP 2 achieved commercial operation in January 2026.

Asia

Indonesia has an estimated geothermal potential of 23GW, the largest in the world, but has only utilized about 2.7 GW (i.e. 13%) of this potential. The Government of Indonesia has made a Nationally Determined Contribution to reduce GHG emissions by 43.2% and achieve net zero emissions by 2060. To meet this target, the Indonesian government has planned to increase the use of renewable energy, with geothermal energy planned to increase by 5.2GW by 2034. To further accelerate the development of renewable energy, Presidential Regulation No. 112 was enacted in 2022, which outlines renewable energy investment incentives and sets more favorable electricity tariffs for renewable energy.

In early 2025, we commenced commercial operation of the 35MW Ijen Power Plant, a joint development with Medco Power Indonesia, which started operation in February 2025. We are making intensive efforts to expand our power plant portfolio in Indonesia. Throughout 2024 and 2025, Ormat won four tenders of fields with the potential of 122MW in total to expand our exploration field portfolio in Indonesia for up to 182MW of geothermal capacity.

In the Product segment, we see increasing market demand for our binary technology. With the successful COD of the 15MW Salak binary power plant in early February 2025 which uses the Ormat system and is the first full single phase binary power plant in Indonesia, we plan to continue to develop and capture the binary market in Indonesia with geothermal and REG power plants.

Plans to build binary power plants have been announced by multiple geothermal companies. As outlined in PLN's Electricity Supply Business Plan for 2025-2034, a binary market totaling 500MW is expected to be ready for development by 2030, offering opportunities for our Product segment.

Since 2004, we have established strong business relationships in the **Turkish** geothermal market and provided our wide range of solutions, including our binary systems, to over 40 geothermal power plants with a total capacity of over 900MW and 96 MW under construction. The 15-year FIT in place and the recent 2026 Turkish Economic Coordination Council addressing issues relating to geothermal energy are cultivating development of new projects and investments which have been at a standstill due to the ongoing economic crises in Turkey.

East Africa

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

In Kenya, there are already several geothermal power plants, including our 150MW Olkaria III complex. The Kenyan government has identified the country's untapped geothermal potential as the most suitable indigenous source of electricity.

According to the Kenya National Energy Compact 2025–2030, the Government of Kenya aims to increase renewable power generation capacity to approximately 5.95 GW by 2030, including about 1.68 GW of geothermal capacity, representing roughly 28% of the targeted renewable generation mix, with the objective of transitioning the national grid from approximately 83% to 100% clean energy sources.

Energy Storage

Energy storage systems utilize surplus available electricity that enables utilities and grid operators 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, 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, energy trading, gas peaker replacement, and transmission and distribution deferral.

In general, the energy storage market is impacted by battery prices that are linked to lithium prices and tariffs affecting China. 2025 was a volatile year for BESS pricing due to the implementation of tariffs and tariff policy changes, as well as the increase in demand due to the enactment of the OBBBA. OBBBA introduced foreign entity of concern (FEOC) requirements for projects starting construction after December 31, 2025, which led to developers (including Ormat) safe harboring prior to the end of 2025 so that ITC can be maintained. For more information, see Part I of this Annual Report, Item 1A "Risk Factors—Risks Related to the Company's Business and Operation—We could be impacted by regulatory and other responses to climate change" and "—Risks Related to Governmental Regulations, Laws and Taxation—The reduction, elimination or inability to monetize government incentives could adversely affect our business, financial condition, future results and cash flows". FEOC restrictions will need to be navigated by all developers moving forward to qualify for ITC benefits. Various battery suppliers are preparing to manufacture batteries in the U.S., which is expected to result in additional tax benefits for projects that will use domestically produced batteries.

According to Wood Mackenzie's Energy Storage Monitor, the U.S. energy storage market added 5,268MW/ 14,465MWh across all segments in Q3 2025. Texas and California were responsible for 82% of the installed capacity. Most of these additions, 4,588MW/13,591MWh, were grid-scale storage facilities which our Energy Storage segment focuses on. This segment's installation capacity increased by 27% over Q3 2024. Wood Mackenzie is forecasting that 93 GW of energy storage will be added to the grid between 2025-2029, with the majority expected to be grid-scale installations.

We currently own and operate 17 grid-scale BESS facilities and two hybrid solar PV and BESS facilities, where revenues are derived from selling energy, capacity and/or ancillary services in merchant markets like PJM, ISO-NE, ERCOT, CAISO and Hawaii. 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, or through long-term contracts with load serving entities, e.g., investor-owned utilities, publicly owned utilities and community choice aggregators. We are also pursuing the development and construction of additional hybrid solar PV and BESS facilities. We believe that interconnection remains the key bottleneck for storage development in the U.S., and a primary driver of project timelines.

Growing grid volatility and the expected acceleration of intermittent generation, driven in part by increasing data center electricity demand, are materially expanding the need for energy storage solutions. These market dynamics have supported the development of new tolling structures in Texas and strengthened tolling pricing in California. By entering into tolling agreements, Ormat enhances the proportion of fixed, contracted revenues within the segment, improving cash flow visibility, strengthening earnings stability, and reducing exposure to merchant power price volatility

We have been awarded two separate 15-year tolling agreements for two Energy Storage facilities in Israel under the tolling agreements that are expected to have a combined capacity of approximately 300MW/1200MWh. The ownership of the projects will be shared, 50/50 between Ormat and Allied Infrastructure LTD, a leading infrastructure company in Israel.

Solar PV

Although there is a renewed focus on fossil fuel energy sources by the new presidential administration, the solar PV market continues to grow and benefits from state renewable portfolio targets as well as the general desire to replace fossil fuel generation with renewable resources. We are monitoring market drivers with the potential to develop solar PV power plants in locations where we can offer competitively priced power generation. We currently operate 60MW of standalone solar PV generation and recently commissioned a 42MW solar PV plus 35MW/140MWh BESS project in the Imperial Valley in California and acquired 30MW solar PV plus a 30MW/120MWh BESS project in Hawaii. We also have a pipeline of hybrid PV and BESS development projects in various western states, targeting future utility procurement.

In addition, Ormat continues to focus on adding solar PV systems to some of our operating geothermal power plants to reduce internal consumption loads. Since 2019, we successfully placed in service 48MW of solar PV augmentation systems and acquired an additional 20MW of solar PV augmentations adjacent to operating geothermal power plants in Nevada and are currently developing an additional 36MW.

Operations of our Electricity Segment

How We Explore and Evaluate Geothermal Resources

We conduct exploration activities globally. It generally takes two to five years from the time we start active exploration of a particular geothermal resource to the time we have resource confirmation through drilling and testing. This timeframe assumes the resource is commercially viable and there is an intention to pursue its development. Exploration activities generally involve the phases described below.

Initial Evaluation

We identify and evaluate potential geothermal resources through field investigations using a robust geoscience program identified through both public and private data sources. On average, our expenses for an initial evaluation range from approximately $10,000 (mainly in the U.S.) to $50,000 (mainly for international prospects) including travel, chemical analyses, and data acquisition.

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

Land Acquisition

We acquire land rights to any geothermal resources that 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.

For most of our current exploration sites in the U.S., we acquire rights to use the geothermal resource through land leases with the BLM (which regulates leasehold interests in U.S. federal land), with various states, or through private leases. 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 sites we acquire. These surveys are conducted incrementally considering relative value and cost, and the geologic model is updated continuously.

We make a further determination of the commercial viability of the potential 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. We generally only move forward with those sites that we believe have a moderate to high probability of successful development.

Exploratory Drilling & Testing

We drill exploratory wells on the high priority, relatively low risk sites to confirm and/or define a geothermal resource. 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, business, and portfolio management 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 exploration strategy, and conceptual model of the resource. The type of exploratory drilling performed varies and can range from shallow temperature gradient wells to medium depth core drilling to full-size exploration wells. The exploration program typically focuses on the lowest cost option to de-risk the prospect such as temperature gradient wells to delineate a thermal anomaly and further de-risk targets with larger diameter wells. However, exploration costs, prior to drilling of a full-size well, are $1.0 million to $5.0 million for each site, not including land acquisition, and depending on the success we see in the early stages of exploration. Outside the U.S. exploration costs can be higher.

If we conclude that a geothermal resource will support a commercially viable power plant, we move to the phase of constructing a power plant at the site. Additional wells may be drilled during the plant construction phase to meet the design point criteria.

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.* The number of production and injection 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. In the last five years, our cost for each production and injection well ranged between $2.1 million to $13.0 million. An average cost for a domestic well was approximately $4.3 million and $8.0 million for international wells.
- *Designing the well field, power plant, equipment, controls, and transmission facilities.* 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.

- *Obtaining any required permits, electrical interconnection and transmission agreements.* The permits and licenses required vary from site to site and are described below under "Environmental Permits".
- *Manufacturing (or in the case of equipment we do not manufacture ourselves, purchasing) the equipment required for the power plant.* Generally, we manufacture most of the power generating unit equipment we use at our power plants. Multiple sources of supply are typically available for all other equipment we do not manufacture.
- *Assembling and constructing the well field, power plant, transmission facilities, and related facilities.* We perform site grading and civil, structural, mechanical, insulation, electrical, control, and communication works required for project execution. Construction materials (such as concrete and rebar), equipment (including cranes and forklifts), and tools are supplied as necessary to complete the work.

In general, it has taken approximately two to three years from the time we drill a production well until a power plant becomes operational. During 2025 in the Electricity segment, we focused on the commencement of operations for the repower of the upgrade of Ormesa 1 and the upgrades to our Olkaria III geothermal power plant. We also focused on construction of the Puna repower in Hawaii, Dominica geothermal power plant in the island of Dominica, Bouillante geothermal expansion in Guadeloupe, and construction of the TOPP2 geothermal power plant in New Zealand that was sold at COD to a third party. We also conducted enhancement work in some other of our operating power plants worldwide.

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.

We may conclude that a prospective geothermal resource will not support commercial operations. In such case, costs associated with exploration activities will be expensed accordingly under the Write-off of Unsuccessful Exploration Activities line item in the consolidated statements of operations in our financial statements.

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.

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

How We Sell Electricity

In the U.S., our customers are investor-owned, publicly owned utilities, and, more recently, data centers operators, Hyperscalers, public and private corporations and CCAs. Outside the U.S., our customers are typically state-owned utilities or privately owned entities. In these markets, we generally operate our facilities under rights granted by a governmental agency through a concession agreement.

In all cases, we enter into long-term contracts, typically PPAs, for the sale of electricity or the conversion of geothermal resources into electricity. Historically, revenue from our power plants under a PPA has consisted of two components: energy payments and capacity payments.

Energy payments are usually based on the actual electrical output delivered by a power plant, measured in kilowatt-hours (kWh). Payment rates may be fixed, indexed to the power purchaser's "avoided" power costs (i.e., the costs the purchaser would have incurred if it generated the power itself), or subject to annual escalation at a predetermined rate.

Capacity payments, on the other hand, are calculated based on the generating capacity or declared capacity of a power plant available for delivery to the customer, regardless of the amount of electrical output actually produced or delivered. Additionally, as an example, one of our power plants in Hawaii is eligible for capacity payments under its PPAs when certain generation levels are met. Conversely, it may be subject to a capacity payment reduction if those levels are not met.

How We Finance Our Power Plants

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 operations, as well as proceeds from loans under corporate credit facilities, bonds (including green bonds), public debt and equity offerings, senior unsecured corporate bonds, and the sale of equity interests and other securities. Our debt financing permits the development of power plants with a limited amount of equity contributions, but also increases the risk that a reduction in cashflow 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 subsidiaries to us are contingent on compliance with financial and other covenants contained in the applicable finance documents.

In 2025, we entered into several corporate and project finance loans, renewed our commercial papers and expanded our revolving credit facilities to support our geothermal and storage growth. In addition, we monetized PTCs and ITCs from our Heber geothermal complex and BESS projects.

Description of Our Leases and Lands

We have domestic leases on approximately 434,430 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:

- ~78% of the acreage under our control is leased from the U.S. government, mainly through the BLM. Roughly 3% of that acreage is currently suspended;
- ~18% is leased or subleased from private landowners and/or leaseholders; and
- ~4% is owned by Ormat.

Internationally, our land position includes approximately 5,006 acres in various countries.

BLM Geothermal Leases

Certain of our domestic project subsidiaries have entered into geothermal resource 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. 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, 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 35-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 10 years of production and 3.5% thereafter. The royalty rate for geothermal resources sold by the geothermal lessee or an affiliate in an arm's length transaction is 10.0% of the gross proceeds from the arm's length sale.

The holder of a BLM geothermal lease has the ability to request in writing that the BLM suspend operations related to certain leases or an approved unit for reasons that negatively impact the operator's ability to develop the resource. BLM reviews these requests and determines if the suspension is justified. If a suspension is approved the operator is no longer required to drill, produce geothermal resources or pay rents or royalties during the suspension and the lease term will be extended by the length of time the suspension is in effect. Leases can be unsuspended via a written request to BLM and when the suspension ends the operator resumes rental and royalty payments along with drilling and production requirements.

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.

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 U.S.

Project Name	Size (MW)	Technology	Resource Cooling	Customer	PPA Expiration
Blue Mountain	22	Geothermal water-cooled binary system	3 to 4°F per year	NV Energy	2047
Brawley	3	Geothermal water-cooled binary system	Depends on the mix of used production wells , with current decline rate around 1°F per year	SCE	2031
Brady Complex	24	Geothermal air and water-cooled binary system	Brady and Desert Peak 2 - declining at less than 2°F per year. DP2 declining at less than 1°F per year	Brady - SCPPA DP2 - NV Energy	Brady — 2043 Desert Peak 2 — end of 2053
Brady Solar	30	Solar PV System	NA	Internal use (5)	NA
Don A. Campbell Complex (1)	28	Geothermal air-cooled binary system	Declining at 3-4°F per year	SCPPA	Phase 1 - 2034 Phase 2 -2035
Heber Complex	91	Geothermal binary systems using both water and air-cooled systems	1°F to 2°per year	SCPPA and Peninsula Clean Energy (PCE), CPA	Heber 1 — 2051 Heber 2 — end of 2038 Heber South — End of 2037
Jersey Valley	8	Geothermal air-cooled binary system	Under 2°F per year	Nevada Power Company	2032
Mammoth Complex	65	Geothermal air-cooled binary system	1°F per year	PG&E and Southern California Edison (will be replaced by a PPA with Calpine). Monterey Bay, SCPPA and SVCE	G-1 and G-3 - 2033 CD4 - 2047 G-2 plant - 2037
McGinness Hills Complex (7)	141(4)	Geothermal air-cooled binary system	5°F per year	Nevada Power Company and SCPPA.	Phases 1 and 2 - 2033 Phase 3 - 2043.

Project Name	Size (MW)	Technology	Resource Cooling	Customer	PPA Expiration
Neal Hot Springs	22	Geothermal air-cooled binary system	1.5°F over the past year	Idaho Power Company	2038
OREG 1	22	Geothermal air-cooled binary system	NA	Basin Electric Power Cooperative	2031
OREG 2	22	Geothermal air-cooled binary system	NA	Basin Electric Power Cooperative	2034
OREG 3	5.5	Geothermal air-cooled binary system	NA	Great River Energy.	2029
Ormesa Complex	40	Geothermal water-cooled binary system.	1°F to 2°F per year	SCPPA under a single PPA.	2042
Puna Complex	38	Geothermal combined cycle and air-cooled binary system	The resource temperature is stable	HELCO	2027
Raft River	12	Geothermal water-cooled binary system	The resource temperature is stable	Idaho Power Company	2032
San Emidio Complex	39	Geothermal-water-cooled binary system	Temperature declining in response to recent increase in flow from North Valley Plant. Expect to stabilize over next few years.	NV Energy	San Emidio-2038 North Valley-2048
North Valley Solar	7	Solar PV System	NA	Internal use	NA
Steamboat Complex	79	Geothermal air cooled binary system	2°F to 3°F per year	* Steamboat 2 & 3- SCPPA * Galena1 & 3- Nevada Power Company * Galena 2 & Steamboat Hills- SCPPA	Steamboat 2 and 3- 2043 Galena1- 2026 Steamboat Hills and Galena 2 - 2043 Galena 3- 2028
Steamboat Complex Solar	17	Solar PV System	NA	Internal use (5)	NA
Tungsten Mountain Geothermal	41	Geothermal air and water-cooled binary system	About 3°F to 4°F per year	SCPPA	2043
Tungsten Mountain Solar	12	Solar PV System	NA	Internal use (5)	NA
Tuscarora	17	Geothermal hybrid air and water-cooled binary system	1°F to 2°F per year	Nevada Power Company	2032
Dixie Valley (6)	64	Geothermal air-cooled binary system and water-cooled flash system.	1 to 2°F per year	SCE	2038

Project Name	Size (MW)	Technology	Resource Cooling	Customer	PPA Expiration
Beowawe	20	Geothermal air-cooled binary system	Temperature beginning to stabilize following increase in flow from Beowawe upgrade, expect to moderate over next few years	NV Energy	2053
Beowawe Solar	6	Solar PV System	NA	Internal use [5]	NA
Wister	20	Solar PV System	NA	San Diego Gas & Electric	2042
Stillwater Complex	14	Geothermal air-cooled binary system	1°F to 2°F per year	NV Energy	2029
Stillwater Solar PV I	20	Solar PV System	NA	NV Energy	2029
Stillwater Solar PV	20	Solar PV System	NA	Wynn Las Vegas	2025
Salt Wells	10	Geothermal air-cooled binary system	1°F to 2°F per year	NV Energy	2029
Cove Fort	18	Geothermal air-cooled binary system	The resource temperature is stable	Salt River Project	2033
Woods Hill	20	Solar PV System	NA	Seven different off-takers in Connecticut	2038

Foreign Power plants

Project Name	Size (MW)	Technology	Resource Cooling	Customer	PPA Expiration
Amatitlan (Guatemala)	20	Geothermal air-cooled binary system and a small back pressure steam turbine (one MW)	About 2°F per year	INDE and another local purchaser.	End of 2027
Bouillante (France)	15	Geothermal direct steam turbines with sea-water cooling system	The resource temperature is stable	EDF pursuant to a PPA.	2030
Olkaria III Complex (Kenya) [2]	150	Geothermal air-cooled binary system	Temperature stabilized in 2024	KPLC	Plant 2 - 2033 Plant 1&3 - 2034 Plant 4 - 2036
Platanares (Honduras) [3]	30[4]	Geothermal air-cooled binary system	4°F to 5°F per year	ENEE	2047
Zunil (Guatemala)	20	Geothermal air-cooled binary system	The resource temperature is stable	INDE	2034
Sarulla Complex - (Indonesia)	42	Geothermal Combined Cycle steam and air cooled binary systems	NIL power plant - 3°F per year and SIL - about 1°F per year	PLN	2047
Ijen (Indonesia)	17[9]	Geothermal air-cooled binary system	NA[8]	PLN	2055

1. Don A. Campbell has experienced cooling since mid-2016, with a 3-4°F decline in the last year, causing a reduction in its generating capacity. A temperature mitigation program is ongoing.
2. The complex is experiencing heavy curtailments by KPLC, however the capacity payments are paid on the full generating capacity.
3. We hold the Platanares assets, including the project's wells, land, permits and a PPA, under a BOT structure for 15 years from September 26, 2017, the date the Platanares plant commenced commercial operation. A portion of the land on which the project is located is held by us through a lease from a local municipality.
4. In the second quarter of 2022, Sarulla agreed with its banks on a framework that will enable it to perform remediation works that are aimed to restore the power plants' performance. The first phase of the recovery plan included the drilling of an additional production well, which was successful, and certain modifications to surface equipment are still underway. Following the positive indications from the first phase, during the second quarter of 2024, Sarulla commenced discussions with the banks towards implementation of an additional phases and expects to commence drilling of additional 2 wells, starting in 2026, aiming for the same target zone of the successful well drilled earlier.
5. The Tungsten, Brady, Steamboat, Beowawe, North Valley and Still Water Solar PV power plants generate energy that is used for the auxiliary power of the geothermal power plants.
6. McGinness Hills Complex has experienced cooling in the last few years, with an approximately 5°F decline in the last year. Temperature mitigation program is ongoing, investigating new production and injection areas.. In addition, the complex experienced heavy curtailments during the year as a result of NV Energy T-line maintenance.
7. Ijen power plant in Indonesia commenced operation in February 2025.

8. Represents Ormat's 49% equity share in the project
9. Amatitlan PPA is expected to expire at the end of 2027, we are currently working to extend the PPA.

Future Projects

Projects Released for Construction

We have several projects in various stages of construction, including 11 projects that we have released for construction with a total capacity of 136.5MW and one project with capacity of 10MW to 15MW that is in the early stages of construction.

These projects are expected to have a total geothermal generating capacity of between 101MW and 106MW (representing our interest) and solar PV projects with a total capacity of 36MW.

Project Name	Location	Expected Size (MW)	Technology	Customer	Expected COD	Current Condition
Zunil	Guatemala	5	Geothermal air-cooled binary system	INDE	2027	Drilling was delayed to 2027
Bouillante	Guadeloupe	10	Geothermal water-cooled binary system	EDF	Q3 2026	Construction progressing
Dominica	Dominica	10	Geothermal air-cooled binary system	DOMLEC	Q1 2026	Construction completed. Commissioning undergoing.
Cove Fort upgrade	Utah, U.S.	7	Geothermal air-cooled binary system	Salt River Project	Q2 2026	Construction ongoing
Stillwater upgrade	NV, U.S	3	Geothermal air-cooled binary system	NV Energy	Q4 2026	Plant partially online. Work in progress.
Salt Wells upgrade	NV, U.S	5	Geothermal air-cooled binary system	NV Energy	Q2 2026	Main equipment shipped.
McGinness Solar	Nevada, U.S.	14	Solar PV	NA	Q4 2026	Engineering and procurement ongoing
Heber Complex	California, U.S.	27	Geothermal air-cooled binary system	SCPPA	H2 2027	Engineering and procurement ongoing
Heber Complex	California, U.S.	22	Solar PV	NA	H2 2027	Engineering and procurement ongoing
Blue Mountain upgrade	Nevada, U.S.	3.5	Geothermal	NV Energy	2027	Project release
Greenfield	Nevada, U.S.	30	Geothermal	TBD	2027	Project release
Total		**136.5**				
Carson Lake	Nevada, U.S.	10 - 15	Geothermal air-cooled binary system	No PPA	TBD	On Hold

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

We also have projects under various stages of development in the U.S. that we estimate will increase the generating capacity of our geothermal and Solar PV projects by approximately 24MW. 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. 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 2026.

Project	Location	Technology	Size (MW)	Customer	Expected COD
Dixie Meadows	Nevada, U.S.	Geothermal	12	SCPPA	On Hold
Blue Mountain	Nevada, U.S.	Solar PV	12	NA	H1 2027
Total			**24**		

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.

Our current land position is comprised of various leases, concessions and private land for geothermal resources in **50** prospects across the western U.S., Latin America and Africa. In the U.S. we hold **34** prospects:

- 23 prospects in Nevada
- 5 prospects in California
- 2 prospects in Oregon
- 3 prospects in Utah
- 1 in New Mexico

Outside the U.S. we hold **16** prospects:

- 8 prospects in Indonesia
- 4 prospects Ethiopia
- 2 prospects in Guatemala
- 1 prospect in Honduras
- 1 prospect in New Zealand

Competition

Electricity Segment

Ormat's Electricity Segment competes with geothermal developers during the early stages of project development. At this stage, the company must either acquire resource rights or purchase a site. If Ormat is unsuccessful in securing the lease, the acquiring entity may still become a customer of Ormat’s Product Segment.

Our primary competitors are smaller, pure-play developers focused on resource identification and development. In the U.S., industry newcomers are emerging, targeting advanced subsurface geothermal systems and competing for geothermal leases using innovative drilling techniques and technologies. Internationally, competitors gain expertise from projects in their home regions. In Indonesia, Ormat faces competition from companies such as Kaishan, PT Pertamina Geothermal Energy, PT Star Energy, and, in a recent tender, Chevron (in partnership with Pertamina). Although Impex remains active in Japan's geothermal sector, Ormat has yet to encounter direct competition from Impex. Meanwhile, Turkish developers are increasingly focusing on international market expansion. Ormat also competes with other smaller pure-play geothermal developers and local providers.

In the U.S., higher electricity demand has led to rising PPA pricing and reduced scarcity in acquiring new PPAs. As a geothermal company, Ormat prioritizes markets where its vertical integration offers a competitive advantage, enabling it to develop cost-effective baseload projects.

In addition, recently, a group of venture-backed companies is entering the geothermal industry, primarily focused on enhanced geothermal systems and other next-generation technologies recently started to enter. These companies are leveraging advances in horizontal drilling, subsurface imaging, reservoir stimulation, and closed-loop or hybrid geothermal concepts, often adapted from oil and gas applications. While many of these entrants remain in the pilot or early or advanced commercial stages, they are actively competing for geothermal leases, talent, and public and private funding in the United

States and other markets. As these technologies mature and are deployed at commercial scale, such companies could become competitors to Ormat in the development of future geothermal projects, particularly in regions without conventional hydrothermal resources.

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 turbine competitors are industrial steam turbine manufacturers such as Mitsubishi Heavy Industries, Fuji Electric Co., Ltd. and Toshiba Corporation of Japan, GE/Nuovo Pignone and Ansaldo Energia of Italy.

Our binary technology competitors are manufacturers using the ORC technology. These include Mitsubishi Heavy Industries through Turboden, TICA, a Chinese air conditioning company that acquired Italian Exergy, Egesim, a Turkish electrical contractor who is collaborating with Atlas Copco mainly in the Turkish market, Baker Hughes, one of the world's largest oilfield services and energy technology companies, which provides comprehensive subsurface-to-surface solutions. Internationally, other competitors are Kaishan, a Chinese compressor manufacturer that also develops its own projects and Fuji Electric Co., Ltd of Japan.

While we believe that we have a distinct competitive advantage based on our accumulated experience, 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 operating margins, which in turn impacted our profitability.

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

Energy Storage Segment

In the Energy Storage segment, we face significant competition from companies that have already established businesses in the sector, companies that are seeking to acquire established businesses to gain a foothold in the sector, and new market entrants.

The energy storage space is comprised of a multitude of companies with different business strategies, such as project developers, independent power producers, system integrators, EPC contractors, component suppliers (e.g. batteries, inverters, control software, and balance of plant), and scheduling coordinators, among others.

We continue to develop greenfield projects with great emphasis on the quality of the location and other characteristics that will make for highly profitable projects as well as targeting strategic acquisitions of development assets. Additionally, we believe that our participation and expertise in various parts of the value chain, such as engineering, procurement, construction, project development, operation and maintenance, and asset management and market participation, together with our long-term experience in commercial operations gives us a competitive advantage in the market of utility scale energy storage.

Customers

All of our revenues from the sale of electricity in the year ended December 31, 2025 were derived from fully-contracted energy and/or capacity payments under long-term PPAs with governmental, public 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, 2025
SCPPA (U.S.)	17.8%
NV Energy (U.S.)	13.8%
KPLC (Kenya)	11.9%

Based on publicly available information, as of December 31, 2025, 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- (Negative)	Baa1 (Stable)
HELCO	B+ (Positive watch)	Ba2 (Positive)
Sierra Pacific Power Company	A- (Stable)	Baa2 (Stable)
Nevada Power Company	A- (Stable)	Baa1 (Stable)
SCPPA	AA+ (Stable)	Stable
PG&E	BB (Positive)	Baa3 (Positive)
EDF	BBB+ (Stable)	Baa1 (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 other than EDF (France).

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

Our revenues from the Energy Storage segment are derived from selling energy, capacity services under long term capacity contracts and/or ancillary services in merchant markets like PJM, ISO New England, ERCOT and CAISO or under long-term tolling agreement that secure fixed revenues. In addition, we are pursuing projects that will serve entities, such as investor-owned utilities, publicly owned utilities and community choice aggregators.

Human Capital Resources

Our Team

As of December 31, 2025, we employed 1,648 professionals across our global operations with the following breakdown by country: 531 in Israel, 797 in the U.S., and 320 in other countries along with 70 temporary and contracted team members.

Workforce Health and Safety

The health and safety of our employees, subcontractors, the public, and the environment is our overarching priority. We proactively identify, assess and manage risks in the facilities and offices that we own and operate. Our goal is to report, analyze, learn and improve performance to reduce the number of safety incidents.

Competitive Compensation and Benefits

We are committed to providing competitive and comprehensive benefits. Our offerings include market-aligned compensation, comprehensive healthcare coverage, short- and long-term disability benefits, and paid maternity and paternity leave. We provide retirement and pension plans in all eligible countries, including 401(k) options in the U.S. In addition, we sponsor professional development and learning opportunities to foster career growth. These benefits help us attract and retain top talent—driving innovation and long-term success.

Employee Investment

We are committed to empowering our employees through education, development, and training. Our programs include technical and soft skills training offered in-person and online, as well as leadership development programs.

Collective Bargaining Agreements & Employee Unions

As of December 31, 2025, the only employees currently represented by a labor union are the employees of our Bouillante power plant located in Guadeloupe and our battery and maintenance employees in Philadelphia. The employees in Guadeloupe are represented by the Confédération Générale du Travail de Guadeloupe and those in Philadelphia by the IBEW Local 777.

We do not maintain collective bargaining agreements for our Israeli employees. However, certain provisions of a sector-wide agreement between the Histadrut (General Federation of Labor in Israel) and the Coordination Bureau of Economic Organizations may apply to some non-managerial employees in finance, administration, and sales and marketing roles. These provisions primarily address cost-of-living adjustments, workday length, minimum wages, workplace accident insurance, vacation and sick leave, severance pay, pension contributions, and other employment conditions.

We currently provide benefits and working conditions that meet or exceed these standards. To date, we have not experienced any labor disputes, strikes, or work stoppages, and we remain committed to fostering a positive and collaborative work environment for all employees.

Insurance

We maintain partial physical damage and business interruption insurance, including the perils of flood, volcanic eruption, earthquake and windstorm, cyber coverage, general and excess liability, pollution legal liability, control of well, drilling rigs, construction risks, as well as customary worker's compensation and automobile, marine transportation insurance, charterers' liability and such other commercially available insurance as is generally carried by companies engaged in similar businesses and owning similar properties in the same general areas as us. Such insurance covering our properties extends to Ormat and/or our owned, controlled, direct or indirect affiliated or associated companies, subsidiary companies or corporations in amounts generally based upon the estimated replacement value and maximum foreseeable loss of our facilities (provided that certain perils including earthquake, volcanic eruption and flood coverage are subject to sublimit and/or annual aggregate limits depending on the type and location of the facility) and business interruption insurance coverage in an amount that also varies from location to location but limited to 12 months of operation.

We purchase, when and where available, certain insurance policies to cover a portion or all of our book equity investment to specified political risks involved in operating in developing countries. We hold a global political risk insurance program covering the significant political risks at certain of our locations. This program is issued by the global insurers in the private sector. Such insurance policies generally cover, subject to the limitations and restrictions contained therein, losses derived from a specified governmental act, such as expropriation, political violence, and the inability to convert local currency into hard currency and, in certain cases, the breach of agreements with governmental entities, in approximately 70% of our book net equity investment.

Regulation of the Electric Utility Industry in the U.S.

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 certain Qualifying Facilities, including small power production facilities that use geothermal resources as their primary energy source, 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 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. A sale to a public utility under PURPA at state approved avoided cost rates is generally exempt from FERC rate regulation.

In addition, provided that the purchasing electric utility has not been relieved from its mandatory purchase obligation, PURPA and FERC's regulations 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. In addition, FERC subsequently amended its PURPA regulations to reduce the rebuttable presumption that small power production facilities in organized markets have nondiscriminatory access to markets from 20MW to 5MW. Therefore, the California investor-owned utilities may have a basis to further reduce their mandatory purchase obligation.

With certain limited exceptions, we expect that our power plants in the U.S will continue to meet all criteria required for Qualifying Facility status under PURPA. However, 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.

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. Additionally, most or all of our power plants and storage projects qualify as exempt wholesale generators, exempting them from PUHCA requirements as well.

FPA

Pursuant to the FPA, FERC has exclusive jurisdiction over the rates for most wholesale sales of electricity and transmission of electricity 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 might also permit the off-taker, 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.

Additionally, FERC possesses civil penalty authority, up to approximately $1.6 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 $1.6 million a day for violating mandatory reliability standards. We examine our projects' compliance with NERC standards on an ongoing basis and begin work on the process of NERC registration as new projects approach the threshold at which NERC standards become applicable.

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, Peninsula Clean Energy, 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. Peninsula Clean Energy is regulated by the CPUC.

Under Hawaiian law, non-fossil generators are not subject to regulation as public utilities. Hawaiian 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 operation 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 four types of wells: (i) resource confirmation 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, (iii) injection wells to inject the brine back into the subsurface resource, and (iv) monitoring wells to monitor the geothermal resource. For example, on BLM lands in Nevada, California, Oregon, Utah, 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 also be obtained from the Nevada Division of Minerals. Those wells in Nevada to be used for injection will also require Underground Injection Control (UIC) permits from the Nevada Division of Environmental Protection, Bureau of Water Pollution Control. All geothermal wells drilled in Oregon (except on tribal lands) 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 Idaho Department of Water Resources (IDWR) and injection wells also require UIC permitting through IDWR. Geothermal wells in Utah require permits from the Utah Division of Water Rights, and injection wells require a permit from the Utah Department of Environmental Quality. Geothermal wells on private lands in California require drilling permits from the California Department of Conservation's Geologic Energy Management Division (CalGEM). 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 CalGEM.

The 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, including managing fugitive dust emissions during construction. 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 mud from well construction, as well as to manage certain discharges to surface impoundment, if any.

The fourth category of permits, required in Nevada, California, Oregon, Utah, 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 it takes to receive such permits and the associated costs of compliance.

Our Battery Energy Storage System (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, 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, or could lead to contamination of the environment and result in material cleanup requirements or other responsive obligations under applicable environmental laws.

Regulation Related to the Energy Storage Segment

Our participation in the energy storage space and in energy management requires 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, CAISO, ISO-NE, and ERCOT. Among other requirements, our market-based rate sellers are subject to certain market behavior and anti-market manipulation rules and, if any of our subsidiaries were deemed to have violated any one of those rules, such subsidiary could be subject to potential disgorgement of profits associated with the violation and/or suspension or revocation of market-based rate authority, as well as criminal and civil penalties. If the market-based rate authority for one (or more) of our subsidiaries was revoked or it was not able to obtain market-based rate authority when necessary, and it was required to sell energy on a cost-of-service basis, it could become subject to the full accounting, record keeping and reporting requirements of FERC. 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 Independent System Operator and wholesale power market administrator, the AMM, for the operation 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, and need power purchase agreements with independent power producers to cover that demand 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 for new generation equipment. In August 2024 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 excess amounts of electric energy for commercialization, provided the capacity does not exceed 5MW. 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 been licensed by the EPRA. 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 EPRA under the Kenyan Energy Act. KPLC's retail electricity rates are subject to approval by the EPRA. The EPRA has an expanded mandate to regulate not just the electric power sector but the entire energy sector in Kenya. Transmission of electricity is 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 dominated by geothermal, wind and, presently at a lower level, solar is 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. The implementation of the Renewable Energy Auctions Policy by the Ministry of Energy, which was expected to replace the feed-in-tariff policy with respect to solar, wind and other renewable energy projects exceeding 20MW, has yet to be implemented. 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 Electricity Law No. 32 of 2009 (in conjunction with Government Regulation In Lieu of Law No. 2 of 2022 on Job Creation*/Omnibus Law) is the principal regulation for the electricity industry in Indonesia which divides the industry into two broad categories: (1) electrical power provision, covering electric power generation, transmission, distribution and sales, and (2) electrical power support such as services (consulting, construction, installation, operation & maintenance, certification & training, testing etc.) and industry (manufacture of tools, power plant equipment, cables, electrical equipment, etc.). The Electrical power provision business is dominated by PLN (a state-owned enterprise), which is the sole owner of transmission and distribution assets and 91.6% of the power generation assets as per 2023. Private sector participation in power generation is allowed through an IPP scheme, mostly done through tenders or direct appointment for

some power sources such as geothermal. Geothermal power is regulated by The Geothermal Law issued in 2014 (Law No 21 of 2014, as also amended by the Indonesian Omnibus Law in 2022), that endorses private participation as geothermal IPP. The Central government conducts tenders for geothermal fields, awarding a Geothermal Business License for the winner. Geothermal Business License holders can conduct exploration and feasibility studies within five years and subject to two extensions of one-year each, 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. In 2022, Presidential Regulation No. 112 was enacted with the aim of accelerating renewable energy. This regulation replaces the basis of the renewable energy tariff from the average electricity generation basic cost to a ceiling price. In this scheme, the tariff is negotiated between the IPP and PLN and must not be higher than the ceiling tariff set for a particular type of renewable energy power plant, which then is multiplied by a factor based on location.

Guadeloupe

EDF is the transmission and distribution utility in Guadeloupe and also operates a significant portion of Guadeloupe's fossil fuel 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 the French electricity and gas markets 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, which provides the legal framework for the electricity sector and replaces the previous Electricity Subsector Framework Law. 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. 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 has moved 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 also approved a Law of Incentives for Renewable Energy Projects, Decree 70-2007, further amended by Decree 138-2013, with additional incentives such as to solar PV projects. 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.

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 terminate 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, biomass facilities owners and operators and all other companies engaged in energy-intensive industrial processes such as glass, steel and other. 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.

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 quality, 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 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, we enter into 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.

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

Production pumps

Ormat delivers a full-service approach to Production Pump sales, offering not just the pump itself but the entire supporting ecosystem, including auxiliary systems, control systems, and electrical equipment. By leveraging its own inventory of pump components, Ormat provides competitive lead times and rapid delivery. Drawing on the extensive operational knowledge gained from managing over 140 pumps across its global fleet, Ormat provides expert support throughout the process, from pump definition and selection to installation supervision. Each pump is backed by a minimum 12-month warranty, reinforcing Ormat's commitment to reliability and customer confidence. This comprehensive offering positions Ormat as a trusted partner for geothermal operators and strengthens its leadership in the renewable energy sector.

Backlog

We have a product backlog of approximately $352.0 million as of February 25, 2026, which includes revenues for the period between January 1, 2026 and February 25, 2026, compared to $340.0 million as of February 22, 2025, which included revenues for the period between January 1, 2025 and February 26, 2025. The backlog as of February 25, 2026 includes an amount of approximately $100 million related to Topp 2, which we agreed to sell in January 2026 to a third party.

The following is a breakdown of the Product segment backlog amount (in millions)by country as of February 25, 2026:

Country	Backlog Amount	Percentage of Backlog
New Zealand	$238.0	67.7%
Asia	90.5	25.7%
Dominica	6.6	1.9%
Portugal	5.2	1.5%
Guatemala	8.0	2.3%
U.S.	2.8	0.8%
Others	0.6	0.2%
Total	$351.7	100%

The following is a breakdown of the Product segment backlog by technology as of February 25, 2026:

	% of Total Backlog	Latest Expected Completion
Geothermal	99.3%	2026
Recovered Energy	0.1%	2026
Others	0.6%	2026

Operations of our Energy Storage Segment

Storage Projects

In addition to our Geothermal activity, we own, operate and develop energy storage projects in the U.S. at a total capacity of 415MW/1,540MWh.

Under construction and development

We have 7 projects in various stages of construction and development with a total capacity of 410.0MW, as listed in the table below.

Project Name	Customer	Location	Size (MW)	MWh	Type of contract	Expected COD
Bird Dog	Equilibrium Energy	TX	60	120	Merchant	Q2 2026
Shirk	CAISO	CA	80	320	Merchant and RA contract	Q1 2026
Griffith	CAISO	CA	100	400	TBD	2027
Rosh Pina & Bet Alpha	Israeli Electricity Authority	Israel	150	600	Full tolling	2028
Brur Hayil	Israeli Electricity Authority	Israel	20	100	Merchant	2028
Total			**410.0**	**1,540.0**		

Energy Storage Pipeline

For an energy storage prospect to move into the EPC phase, it requires site control, an executed interconnection agreement, permits from all authorities and a viable financial model. We have a substantial pipeline of approximately 2.7GW/10.0GWh of projects in different stages of development for future growth in the U.S. and Israel that we expect will help support our target to reach an energy storage portfolio of between 950-1050MW/2,500-2,900MWh by the end of 2028.

ITEM 1A. RISK FACTORS

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

Risks Related to the Company's Business and Operation

Our financial performance depends on the successful operation of our geothermal, REG and solar PV power plants under the Electricity segment, as well as our Energy Storage facilities, which are subject to various operational risks.

Our financial performance depends on the successful operation of our geothermal, REG, and solar PV power plants. In connection with such operations, we derived 70.1% of our total revenues for the year ended December 31, 2025 from the sale of electricity and 8.0% from the sale of services in the Storage segment. The cost of operation and maintenance and the operating performance of our geothermal power, REG, and solar PV power plants and our storage facilities, or of third service providers, may be adversely affected by a variety of factors, including:

- regular and unexpected maintenance and replacement expenditures;
- shutdowns due to the breakdown or failure of our equipment or third-party equipment of the transmission serving utility;
- labor disputes or collective bargaining arrangements with employees that successfully unionize;
- labor market risk;
- the presence of hazardous materials on our power plant sites;
- continued availability of cooling water supply;
- low run times of compressors at recovered energy-based plants (such as low run times of the compressor stations heating our OREG power plants, which led to power generation and the likely loss of a customer agreement at one of these plants);
- 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, such as the 2018 volcanic eruption that occurred in Hawaii's Big Island impacting our Puna project);
- the aging of power plants (which may reduce their availability and increase the cost of their maintenance);
- unsuccessful augmentation of batteries or other necessary equipment; and
- cyber-attacks that may interrupt the operation of our power plants.

Any of these events could significantly increase the expenses incurred by our storage facilities or our power plants, or could reduce the overall effectiveness of our storage facilities or the 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.

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 and as a result would adversely affect our growth plans. 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. Recent examples include the Olkaria complex, which experienced a reduction in generation due to lower performance of the well field; the Sarulla complex, where we experienced a reduction in generation primarily due to wellfield issues at one of its power plants, as well as equipment failures which resulted in a decrease in profitability; and our Brawley power plant in California, where we recorded a non-cash impairment loss due to electricity generation lower than its generating capacity due to continuous wellfield issues. For more information on the ongoing impacts of these, see "Property, Plant and Equipment and Construction-In-Process – Impairment of Long-Lived Assets.

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 ground subsidence or inflation. Inflation and subsidence, if not controlled, can adversely affect farming operations and other infrastructure at or near the land surface.

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

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

There are uncertainties and risks associated with our strategic plan described in Part I of this Annual Report, Item 1, "Business—Business Goals," 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 several reasons. 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. 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;
- obtain financing on terms we consider acceptable, or at all, which we may need, for example, to develop new projects, 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;
- provide energy storage services that keep pace with rapidly changing technology, customer preferences, equipment costs, increasing raw materials and transportation costs, market conditions and other factors that are unknown to us now that will impact these markets;
- manage the risks and uncertainties associated with our operating storage facilities and future development of storage and geothermal projects which may operate as facilities without long-term sales agreements, including the variability of revenues and profitability of such projects;
- 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
- recruit appropriate employees and labor market challenges.

Implementing the plan may also involve various costs, including, among other things: opportunity costs associated with forgone 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 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 and/or geographic base may expose us to customers with different credit profiles than our current customers or foreign countries in which we will have to learn the business and political environment.

Our investments and profitability in battery Energy Storage System (BESS) may be negatively affected by a number of factors, including increases in storage costs, expanded trade restrictions, risk of fire and volatility in merchant prices.

We devote resources to research and development related to our Energy Storage segment, and the ability of these BESS facilities to meet our performance expectations is subject to the risks inherent in newly constructed facilities, including, but not limited to, system failures, outages and design and/or construction flaws, latent defects and degradation of equipment in excess of our expectations. Battery storage facilities utilize new technologies with a relatively limited history with respect to reliability and performance. We will need to innovate in order to keep pace with industry developments and customer expectations, and there is no guarantee that such new technologies will perform as expected. If any of our battery energy storage services contains manufacturing defects or any undetected defects, errors or bugs in hardware or software, our business and financial results could be adversely affected.

The energy storage market is impacted by battery prices that are linked to lithium prices and tariffs affecting China. 2025 was a volatile year for BESS pricing as tariffs were enacted and changed as well as the increase in demand due to the enactment of the OBBBA. These tariffs, the adoption and expansion of trade restrictions, the occurrence of a trade war or other governmental action related to tariffs, trade agreements or related policies have the potential to adversely impact our supply chain and access to equipment, our costs and ability to economically serve certain markets. If additional measures are imposed or other negotiated outcomes occur, our ability or the ability of our suppliers to purchase these products on competitive terms or to access specialized technologies from other countries could be further limited, which could adversely affect our business, financial condition and results of operations.

The OBBBA also introduced FEOC requirements for projects starting construction in 2026 and beyond, which led to developers safe harboring equipment prior to the end of 2025 so that ITC can be maintained. For more information, see Part I, Item 1 "Business—Business Opportunities—United States—Federal." The FEOC rules may have the result of leading to pressure for increased supply chain costs, reduced supply chain options, and may lead to increased priced pressure for energy products and projects. Various battery suppliers are preparing to manufacture batteries in the U.S., which is expected to result in additional tax benefits for projects that will use domestically produced batteries. The reduction, elimination or inability to monetize government incentives and/or continued volatility in the tariff, could adversely affect our business, financial condition, future results and cash flows.

The revenues from our BESS facilities fluctuate over time since a large portion of such revenues are generated in the merchant markets, where price volatility is inherent. This volatility in merchant prices may adversely effect our Energy Storage profitability. We are also experiencing intense competition in the energy storage market from independent power producers, developers, and third-party investors.

Any of these events could significantly increase the expenses incurred by our BESS facilities or could significantly reduce or entirely eliminate the revenues generated by one or more of our BESS facilities 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 investments in next-generation geothermal technologies including in EGS involve significant risks and may not achieve anticipated returns.

We have made, and may continue to make, investments in EGS, which is an emerging geothermal technology that differs materially from conventional geothermal development. EGS projects seek to create or enhance geothermal reservoirs through advanced drilling, stimulation, and reservoir management techniques. While EGS has the potential to

expand the geographic and resource base for geothermal energy, the technology has not yet been widely deployed at commercial scale.

EGS projects involve substantial technical, operational, and geological uncertainties, including risks related to reservoir creation and sustainability, drilling success rates, well productivity, thermal recovery, induced seismicity, permitting, and long-term system performance. There can be no assurance that EGS projects in which we invest will achieve expected technical milestones, operate reliably, or produce energy at commercially viable levels.

In addition, EGS projects generally require significant upfront capital investment, extended development timelines, and may be dependent on continued technological advances, third-party expertise, government incentives, or regulatory support. Cost overruns, delays, or changes in regulatory frameworks could adversely affect project economics. Further, because EGS is a relatively nascent technology, there is limited operating history to validate assumptions regarding long-term performance, maintenance requirements, and decommissioning obligations.

If our EGS investments fail to progress as anticipated, experience technical or regulatory setbacks, or do not achieve commercial viability, we may be required to impair some or all of our investments, incur additional costs, or forego expected returns. Any such outcomes could have a material adverse effect on our results of operations, financial condition, and cash flows.

Concentration of customers, specific projects 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 the ability of each customer 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 in the marketplace 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. Moreover, there can be no assurance that we will be able to enter into replacement agreements on favorable terms or at all.

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 certain of our significant customers. In the Electricity segment, we are exposed to the credit and financial condition of KPLC that buys the power generated from our Olkaria III complex in Kenya. In 2025, KPLC accounted for 11.9% 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, 2025, the amount overdue from KPLC in Kenya was $29.5 million of which $21.1 million was paid in January and February of 2026. In addition, KPLC recently requested more favorable rates on its existing PPAs with it. Any change in KPLC's financial condition or the terms of our agreement with KPLC, may adversely affect us.

In Honduras, as of December 31, 2025, the total amount overdue from ENEE was $20.3 million of which $1.0 million was collected in January and February of 2026. In addition, due to the financial situation in Honduras, the Company may experience additional delays in collection. The Company believes it will be able to collect all past due amounts in Honduras.

We are also exposed to the credit and financial condition of SCPPA and its municipal utility members that account for 17.8% of our total revenues in 2025, 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.

In addition, we generate a significant portion of our revenue from our two largest projects, the McGinness Hills complex in east Nevada and the Olkaria III Complex in Kenya, which together accounted for approximately 23.7% of the total generating capacity of our Electricity segment in 2025. These two facilities accounted for 20.7% of our total revenues for the year ended December 31, 2025. Any disruption to the operation of these facilities would have a disproportionately adverse effect on our revenues and on our profitability. In 2025, we experienced high curtailments in the McGinness Hills complex related mostly to third party grid maintenance that impacted our revenues by approximately $6.3 million.

Our international operations expose us to risks related to the application of international laws and regulations.

Our global operations in countries including Kenya, Turkey, Guadeloupe, Guatemala, Honduras, Indonesia and others require us to comply with the laws and regulations of various governments and regulatory authorities outside the U.S. in addition to legal and regulatory requirements in the U.S. Such foreign laws or regulations may not provide the same type of legal certainty, rights, or judicial processes with respect to our contractual relationships in such countries, as are afforded to our operations in the U.S. A failure to receive adequate judicial or enforcement protection of our contractual rights abroad

may adversely affect our ability to fulfill our contracts successfully and generate revenues therefrom. In particular, the legal and regulatory systems in the foreign jurisdictions where we operate can be characterized by one or more of the following:

- 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;
- Rapidly evolving legal systems may not always coincide with market developments.

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 may apply to us, our subsidiaries, individual directors, officers, employees and agents, and may restrict our operations, trade practices, investment or acquisition decisions or partnership opportunities. These requirements include, but are not limited to, data privacy requirements, labor relations laws, tax laws, competition regulations, import and trade restrictions, economic sanctions, and export requirements.

In particular, our international operations are subject to U.S. and foreign anti-corruption laws and regulations, such as the Foreign Corrupt Practices Act of 1977, as amended (the "FCPA") and other local laws that prohibit corrupt payments to governmental officials or certain payments or remunerations to customers. The FCPA prohibits U.S. companies and their officers, directors, employees and agents acting on their behalf from corruptly offering, promising, authorizing or providing anything of value to foreign officials for the purposes of influencing official decisions or obtaining or retaining business or otherwise obtaining favorable treatment. The FCPA also requires companies to make and keep books, records and accounts that accurately and fairly reflect transactions and dispositions of assets and to maintain a system of adequate internal accounting controls. As part of our business, we deal with state-owned business enterprises, the employees and representatives of which may be considered foreign officials for purposes of the FCPA. As a result, business dealings between our employees and any such foreign official could expose us to the risk of violating anti-corruption laws even if such business practices may be customary or are not otherwise prohibited between us and a private third-party. Violations of these legal requirements are punishable by criminal fines and imprisonment, civil penalties, disgorgement of profits, injunctions, debarment from government contracts as well as other remedial measures.

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 U.S., both in our Electricity segment and our Product segment. In 2025, 40.3% of our total revenues were derived from international operations, and our Electricity segment international operations had higher gross profit than our U.S. operations. Thus, disturbances to and challenges facing our foreign operations, especially in Kenya, could have impacts on our business ranging from moderate to severe. Our foreign operations and our exposure to foreign customers that are in most cases, government owned utilities, 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, such as Turkey's ban on trade with Israel, 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 U.S. 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;
- terrorist acts or other similar events;
- 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;
- attempts by state customers of ours to renegotiate or use political leverage to renegotiate power purchase rates in existing contracts; and
- expropriation and confiscation of assets and facilities, including without adequate compensation.

Electricity Segment. In 2025, the international operations of the Electricity segment accounted for 20% of our total revenues, but accounted for 39% of our gross profit, 49% of our net income and 29% 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 purchaser for our power plants located in Kenya, may adversely affect our Olkaria III complex and our overall results of operations.

Product Segment. With respect to our Product segment, 95% of our Product segment revenues in 2025 came from international sales, primarily New Zealand. 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.

General. 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 operations, such as Kenya and Honduras. 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. Guatemala also experienced several months of anti-government protests in 2023 and 2024. 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.

As a result of these risks, we purchase certain types of political risk insurance policies for selected countries where we operate and which are exposed to political turmoil, geopolitical issues or political uncertainty. While such policies are designed to offer assistance with respect to some political incidents that could give rise to financial liability, it 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.

Conditions in and around Israel, where the majority of our senior management and our main product segment production and manufacturing facilities are located, may adversely affect our operations and may limit our ability to produce and sell our products, and support our Electricity segment.

We are a multinational company and do not derive a majority of our revenues from Israel; however, 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, and we receive supplies for and ship products for our Product segment via the Port of Ashdod, which is also close to the Gaza Strip and its coastline. As such, political, economic and security conditions in Israel and the Middle East region directly affect our operations.

Military conflicts involving Israel, such as a re-escalation of the wars in the Middle East that lasted between 2023 and 2025, could have adverse impacts on our business. Wars could result in military reserve duty call-ups and to our ability to ship our products from Israel, which could disrupt the operations of our Product segment and potentially delay some of our growth plans in the Electricity segment. New business partners may be reluctant to do business with us, and existing partners may hesitate to renew their agreements with us, due to their uncertainty regarding our ability to perform under our commitments in Israel, and/or claim they are not obligated to perform their commitments under those agreements pursuant to force majeure. Government-imposed restrictions on movement and travel and other precautions in wartime taken to address the ongoing conflict have in the past disrupted and may in any future conflicts disrupt our management and employees' ability to effectively perform their jobs. Moreover, the perception that we are an Israeli company could harm our business, due to the application of restrictive laws, policies, boycotts or sanctions that other countries or companies may place on Israel and companies operating there or that may otherwise limit our ability to do trade with, or secure new or existing contracts in, other countries with anti-Israel sentiment (such as Turkey or Indonesia).

Political conditions within Israel could also affect our operations or negatively impact the business environment in Israel due to the reluctance of foreign investors to invest or conduct business in Israel, increased currency fluctuations, downgrades in credit rating, increased interest rates, increased volatility in securities markets, adverse impacts on the labor market, and other related changes in macroeconomic conditions.

Some of our leases will terminate if we do not extract geothermal resources in "commercial quantities" or fail to comply with such leases or applicable law or if the lessor under any such lease defaults on any debt secured by the relevant property.

Most of our geothermal resource leases are for a fixed primary term, and then continue for so long as geothermal resources are extracted in "commercial quantities" or pursuant to other terms of extension. The land covered by some of our leases is undeveloped and has not yet produced geothermal resources in commercial quantities. Leases that cover land which remains undeveloped and does not produce, or does not continue to produce, geothermal resources in commercial quantities and leases that we allow to expire, 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.

Additionally, 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. 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.

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.

Our business development activities may not be successful and our projects under construction or facilities undergoing enhancement and repowering may encounter delays, which may impact our future growth.

We are routinely in the process of developing and constructing new power plants in the ordinary course of business. 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 (including environmental 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 such in cases where we have to handle legal proceedings with respect to environmental permits. 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 U.S., as well as in Indonesia, Guadeloupe, Guatemala, New Zealand and Dominica and we intend to pursue the development of other new plants. In addition, our current growth plans include enhancement and repowering of a number of our operating facilities, including the Zunil, Beowawe, Ijen and Puna power plants and involve replacement of old equipment and optimization of the geothermal field, including repair and enhancement of existing wells and drilling of new wells. Our completion of these facilities' development and/or enhancement 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 events including riots, strikes and weather conditions;
- inability or delays in obtaining permits, licenses and other regulatory approvals;
- inability to satisfactorily complete field development and testing;
- 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, but not limited to, discoveries of contamination, protected plant or animal species or habitat, archaeological or cultural resources, or 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 (for more information, see "–We could be impacted by regulatory and other responses to climate change").

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.

In addition, we enter into various types of arrangements with communities and joint venture partners, including in some cases, indigenous peoples, for the development of projects. In some circumstances, we may be required to notify, consult, or obtain the consent of certain stakeholders, such as indigenous peoples, landowners, and/or municipalities. In some jurisdictions where we have greenfield power projects, it may be possible to claim indigenous rights to land and the existence or declaration of indigenous title may affect the existing or future activities of our projects and impact our business, financial condition and results of operations. Certain of these communities and partners may have or may develop interests or objectives which are different from or even in conflict with our objectives. Any such differences could have a negative impact on the success of our projects.

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, or 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. In certain markets, rapid growth in renewable energy development, including solar, wind, storage and geothermal projects, has increased congestion on existing transmission systems and extended interconnection study timelines. As a result, we may experience delays in securing interconnection approvals, or limitations on available transmission capacity, which could adversely affect project development schedules, and overall project economics.

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. These arrangements are often driven by the magnitude of capital required to complete acquisitions of generating assets, strategic partnering arrangements to access operating expertise, and other geothermal and energy industry wide trends that we presume will continue in the future. Where we hold a minority interest in a joint venture or share control or management with another party in a joint venture (such as in the case of our plant in Guadeloupe), our ability to influence joint venture operations may be limited. As such, our 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.

For example, we hold a 12.75% minority interest in the Sarulla complex and, as a result, cannot control the development of its remediation plan, pace of exploration or development or major drilling decisions. Because we may, in some instances, have a reduced level of influence over our joint ventures, we may not be able to realize some or all of the benefits that we believe will be created from our involvement. If any of the foregoing were to occur, our business, financial condition and results of operations could suffer as a result.

Our operations could be adversely impacted by climate change and other extreme weather events.

We are susceptible to losses and interruptions caused by extreme weather conditions such as droughts, hurricanes, tsunamis, floods, wildfires, and water or other natural resource shortages, occurrences of which may increase in frequency and severity as a result of climate change. Climate change may also produce general changes in weather or other environmental conditions, including temperature or precipitation levels, and thus may impact consumer demand for electricity. 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, at the end of 2024, following wildfires in California, we experienced delays in permitting for our storage facilities as well as a reduction in demand for electricity creating overload on the grid and resulting in unexpected curtailments at some of our power plants, which in turn adversely impacted our revenues in the fourth quarter of 2024. 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. In addition, the potential physical effects of climate change, such as increased frequency and severity of storms, floods, and other climatic events, could disrupt our operations and cause us to incur significant costs to prepare for or respond to these effects. If we experience physical damage to our equipment and infrastructure due to climate-related natural disasters, it could lead to the suspension of our operations, additional costs to restore service and repair facilities, and delays in power generation resulting in lost revenue and potential exposure to legal claims. Such events could also impact our ability to obtain insurance coverage and we may experience rising costs of insurance coverage resulting from any damages to our assets, which could have an impact on our profitability.

Climate change could also affect the availability of a secure and economical supply of water, whether due to an increase in water restrictions, an impact on our ability to obtain water permits, or otherwise. Water is essential for the continued operation of certain of our power plants that use water cooling systems. We monitor water risk carefully. If it is determined that a water supply risk exists that could impact projected generation levels at any plant, risk mitigation efforts are identified and evaluated for implementation.

We could be impacted by regulatory and other responses to climate change and other sustainability-related matters.

As a renewable energy solution provider, we are motivated to identify our opportunities and risks with respect to climate change and take efforts to reduce our GHG emissions and improve our energy efficiency. While we generally view this as an opportunity, uncertainty regarding recent regulation or reduction in incentives in this area could also adversely affect us.

In the U.S., where we have a significant portion of our operations, the U.S. Environmental Protection Agency (the "EPA") has adopted rules that, among other things, establish construction and operating permit reviews for GHG emissions from certain large stationary sources, require the monitoring and reporting of GHG emissions from certain sources and implement standards directing the reduction of methane from certain facilities in the oil and gas sector. Similarly, various states have adopted or are considering adopting legislation and regulation focused on GHG cap-and-trade programs, carbon taxes, reporting and tracking programs and emissions limits. At the same time, no comprehensive climate change legislation has been implemented federally. Additionally, in recent years, "anti-ESG" sentiment has gained momentum, with several U.S. states and the federal government having proposed or enacted "anti-ESG" policies, legislation, or initiatives or issued related legal opinions, such as the EPA's recent determination that it lacks the authority to regulate certain GHG emissions and would no longer stand behind its prior findings that GHG emissions are harmful. The policies of the current U.S. presidential administration also increase the prospect of regulatory ambiguity and change. For instance, while executive orders of the Trump administration from early 2025 suggest a positive posture of the administration toward geothermal energy relative to other renewable sources, the impact of these orders, in the absence of any substantive change in regulation since such orders were issued, remains unclear, and we cannot currently make any assurance about the influence of the policies or political stances of the Trump administration on our business. The BLM has also not issued new permits or renewed certain permits for certain solar technologies supporting geothermal auxiliary loads on U.S. federal lands where we have applied for permits to develop or for renewed permits to continue operating, as further described in

"Risks Related to Governmental Regulations, Laws and Taxation—The absence of new or renewed BLM permits for solar PV projects on U.S. federal lands could impair our development activities, project pipeline and growth prospects."

Uncertainty associated with these regulations, our inability to meet the demands of these regulations or our failure to predict accurately the impact of our response to these regulations could adversely affect our business and prospects. We could also face an increase in competition due to the energy transition, as new entrants of disruptive technologies and/or competitors, including in the solar, wind, and storage sectors, could adversely impact our ability to renew existing PPAs or sign new contracts. On the other hand, anti-ESG related policies, legislation, initiatives, litigation, legal opinions, and scrutiny could result in the Company facing additional compliance obligations, becoming the subject of investigations and enforcement actions, or sustaining reputational harm. The related reduction or elimination of government incentives around renewable energy may also harm us, as described in "Risks Related to Governmental Regulations, Laws and Taxation—The reduction, elimination or inability to monetize government incentives could adversely affect our business, financial condition, future results and cash flows."

Lastly, our sustainability disclosures, a failure to meet evolving stakeholder expectations for sustainability practices and reporting, or expenses required to carry on sustainability reporting and/or meet customer requirements or sustainability targets, may potentially harm our customer relationships and/or subject us to significant costs and liabilities and reputational risks, any of which could adversely affect our business, financial condition and results of operations.

We may not be able to successfully conclude the transactions, 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 to enhance our geothermal portfolio and accelerate growth in our Electricity segment. 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. Completion of M&A transactions may be subject to fulfilling conditions and receiving regulatory approval. 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.

Changes in costs and technology may significantly impact our business by making our power plants and products less competitive resulting in the inability to sign new PPAs for our Electricity segment and new supply and EPC contracts for our Products segment.

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 intermittent 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 and will cause reduction and/or inability to sign new PPAs for our Electricity segment and new supply and EPC contracts for our Products segment. Competition in our Product segment has also, in general, started to our affect our ability to secure new purchase orders from potential customers. This increased competition has led to a reduction in the operating margins, in turn impacting our profitability.

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

Our existing intellectual property rights may not be adequate to protect our business. We occasionally file patent applications which 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). However, the patent application 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 our patent applications. Additionally, the scope of patent protection can be reinterpreted after issuance. Even if our patent applications do issue as patents, they may not issue 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 on 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.

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-party vendors' operations. We may be unable to anticipate techniques used to breach 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. In California, there are obligations on businesses to be transparent with their data privacy practices and vests consumers and employees with rights to access and delete the personal information held by businesses. 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. Any failure to comply with FERC or any of these legal requirements 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.

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. For more information, see "Risks Related to the Company's Business and Operation—We could be impacted by regulatory and other responses to climate change and sustainability-related initiatives."

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 20MW, 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 QF and a utility are not affected. If, in addition to the California utilities' waiver of the mandatory purchase obligation for QF projects that exceed 20MW 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 5MW, 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 absence of new or renewed BLM permits for solar PV projects on U.S. federal lands could impair our development activities, project pipeline and growth prospects.

The BLM has not issued new permits or renewed certain permits for standalone solar facilities, solar projects paired with energy storage, or solar installations intended to support geothermal auxiliary loads on U.S. federal lands where we have applied for permits to develop or for renewed permits to continue operating. While we have not recently experienced formal cancellations, the lack of new approvals and renewals creates significant regulatory uncertainty and may materially limit our ability to advance existing projects or develop new projects in locations that require federal land use permit, rights-of-way, environmental approvals, or other permits.

As a result, we may experience material delays in development timelines, increased project costs, loss of site control, termination or renegotiation of power purchase or interconnection agreements, and potential impairment of development assets. Limitations on access to U.S. federal lands may also reduce the number of viable development sites and increase competition and costs for projects on non-federal lands. Any of these factors could reduce our project pipeline, delay revenue generation, and adversely affect our growth prospects, financial condition, results of operations, and cash flows.

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

Construction and operation of our geothermal power plants, battery energy storage systems and solar PV facilities has benefited, and may benefit in the future, from public policies and government incentives that support energy production (including, in certain cases, renewable energy and enhance the economic feasibility of these projects in regions and countries where we operate. On July 4, 2025, the OBBBA was enacted into law in the United States. The OBBBA allows for geothermal to qualify for 100% PTC or ITC related to projects that start construction by the end of December 2033, 75% PTC or ITC by the end of December 2034 and 50% PTC or ITC by the end of December 2035. These incentives allow the Company to transfer credits to unrelated third parties or enter into tax equity transactions, potentially improving project economics and reducing required Company capital. We expect that the construction and operations of our geothermal power plants, battery energy storage systems and solar PV will benefit in the future from certain aspects of the OBBBA and enhance the economic feasibility of projects in the United States. For information relating to risks of the OBBBA, see Part I, Item 1 "Risk Factors—Risks Related to the Company's Business and Operation—Our investments and profitability in Battery Energy Storage System (BESS) may be negatively affected by a number of factors, including increases in storage costs, expanded trade restrictions, risk of fire and volatility in merchant prices."

There are additional public policy and government incentives that currently benefit and that we expect will benefit the Company in the future in countries outside of the U.S. as well as States within the U.S. The incentives in these jurisdictions include accelerated depreciation tax benefits, rebates, mandated feed-in tariffs and other similar incentives.

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. 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 differently from other renewable energy sources, 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. In addition, although we may have the legal ability to monetize ITCs and PTCs, our ability to do so is subject to market prices and demand, which may be lower than we anticipate. Any of the foregoing outcomes could have a material adverse effect on our business, financial condition, future results, and cash flows.

Our operations are primarily conducted through our subsidiaries, which are separate legal entities, and our cash depends substantially on the performance of our subsidiaries and the power plants they operate, most of which are subject to restrictions and taxation on dividends and distributions.

Our operations are primarily conducted through 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 our ability to obtain and maintain environmental permits and governmental approvals required for development, construction and/or operation may result in liabilities, costs and delays in construction (as well as any fines or penalties that may be imposed upon us in the event of any non-compliance or delays 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 development, 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 and construction 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 development, 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 development, construction or enhancement, could cause our operations to be limited or suspended resulting in fines under the PPA. Permits and governmental approvals may also be delayed during periods of government shutdowns.

We may also be subject to litigation seeking to rescind or delay our receipt of environmental permits and governmental approvals. For example, a lawsuit was filed by the Center for Biological Diversity and the Fallon Paiute-Shoshone Tribe in 2021 that sought to revoke the BLM's approval of the development of our Dixie Meadows geothermal power plant in Nevada, which was later closed without prejudice. There can be no assurance that the Company will be able to obtain the necessary approvals to develop Dixie Meadows as originally intended, or at all.

In addition, 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 U.S., 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.

U.S. federal, state and international income tax law changes could adversely affect us.

The Company continuously monitors and examines the impact of U.S. and international tax law changes, such as the Tax Act, CARES and similar tax law changes internationally, in order to determine the impact it may have on our business. The overall impact of the global tax law changes is uncertain, and our business, financial condition, future results and cash flow, as well as our stock price, could be adversely affected.

The Organization for Economic Co-operation and Development (OECD) has a framework to implement a global minimum corporate tax of 15% for companies with global revenues and profits above certain thresholds (referred to as Pillar 2), with certain aspects of Pillar 2 effective January 1, 2024 and other aspects effective January 1, 2025. Several countries in which the Company operates, have enacted Pillar 2. Pillar 2 rules apply to the Company beginning in the year after December 31, 2025. Based on enacted laws, Pillar 2 is not expected to materially impact the Company's effective tax rate. New legislation or guidance could change this assessment.

Litigation, legal proceedings, regulatory investigations or other administrative proceedings could expose us to significant liabilities and reputational damage that could have a material adverse effect on us.

We are involved in the ordinary course of business and otherwise in a number of lawsuits involving, among other matters, employment, commercial, and environmental issues, and other claims for injuries and damages. We are also involved in the ordinary course of business in regulatory investigations and other administrative proceedings, and we are exposed to the risk that we become the subject of additional regulatory investigations or administrative proceedings. We evaluate litigation claims and legal proceedings to assess the likelihood of unfavorable outcomes and to estimate, if possible, the amount of potential losses. Based on these evaluations and estimates, when required by applicable accounting rules, we establish reserves and disclose the relevant litigation claims or legal proceedings, as appropriate. These evaluations and estimates are based on the information available to management at the time and involve a significant amount of judgment. Actual outcomes or losses may differ materially from current evaluations and estimates. The settlement or resolution of such claims or proceedings may have a material adverse effect on us. We use appropriate means to contest or otherwise respond to litigation and/or regulatory proceedings threatened or filed against us, but the litigation and/or regulatory enforcement environments poses a significant business risk.

Risks Related to Economic and Financial Conditions

We may be unable to obtain the additional 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.

Some of our geothermal power plants 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 or favorable terms to us is necessary for the success of our growth strategy, particularly in enhancing our portfolio through M&A activities. Our attempts to obtain future financings may not be successful or on favorable terms.

In recent years, we have also increased our corporate recourse debt at the holding company level due to our ability to obtain improved economic terms, and in June 2022 we issued, $431.3 million aggregate principal amount of 2.50% convertible senior notes due 2027, and an additional $45.2 million aggregate principal amount of the same notes in July 2024. We refer to these notes collectively as the "Notes". Our existing and any future indebtedness may make it more difficult for us to refinance or borrow additional funds in the future, limiting our ability to pursue our growth strategy.

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 debt obligations may adversely affect our ability to raise additional capital and will be a burden on our future cash resources, particularly if we elect to settle these obligations in cash upon conversion or upon maturity or required repurchase.

Our ability to meet our payment obligations under the Notes, depends on our future cash flow performance. This, to some extent, is subject to general economic, financial, competitive, legislative and regulatory factors, as well as other factors that may be beyond our control. There can be no assurance that our business will generate positive cash flow from operations, or that additional capital will be available to us, in an amount sufficient to enable us to meet our debt payment obligations and to fund other liquidity needs. If we are unable to generate sufficient cash flow to service our debt obligations, we may need to refinance or restructure our debt, sell assets, reduce or delay capital investments, or seek to raise additional capital. Our ability to refinance our indebtedness will depend on the capital markets and our financial condition at such time. We may not be able to engage in any of these activities or engage in these activities on desirable terms, which could result in a default on our debt obligations. As a result, we may be more vulnerable to economic downturns, less able to withstand competitive pressures and less flexible in responding to changing business and economic conditions.

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, restrictions on the conversion of local currency into foreign currency, or the local currency has strengthened significantly against the U.S. dollar, 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.

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, vessels 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 U.S. tariffs on Canada, Mexico and China that were recently imposed or are set to take effect, and the uncertainty surrounding the possibility of expanded trade restrictions among the governments of the U.S. and countries where our suppliers operate, could result in delays in supply

and increased costs. Our development activity is also impacted by the supply delay and cost increase of storage batteries and solar PV panels. Further cost increases of such raw materials, commodities and equipment could adversely affect our profit margins.

Our commodity derivative activity may limit potential gains, increase potential losses, result in earnings volatility and involve other risks.

We enter, from time to time, into commodity derivative contracts to manage our price exposure to our energy storage segment revenue. While these transactions are intended to limit our exposure to the adverse effects of fluctuations of storage services prices, they may also limit our ability to benefit from favorable changes in market conditions, and may subject us to periodic earnings volatility in the instances where we do not seek hedge accounting for these transactions or if the correlation between the hedge and the actual performance of the asset will be lower. Also, in connection with such derivative transactions, we may be required to make cash payments to maintain margin accounts and to settle the contracts at their value upon termination.

Finally, this activity exposes us to potential risk of counterparties to our derivative contracts failing to perform under the contracts. As a result, the effectiveness of our risk management could have an impact on our business, results of operations and cash flows.

We have incurred substantial indebtedness that may decrease our business flexibility, access to capital, and/or increase our borrowing costs, and we may still incur substantially more debt, which may adversely affect our operations and financial results.

As of December 31, 2025, we had $2,659.6 million outstanding aggregate principal amount of long-term debt. Our indebtedness may limit our ability to borrow additional funds for working capital, capital expenditures, acquisitions or other general business purposes, limit our ability to use our cash flow or obtain additional financing for future working capital, capital expenditures, acquisitions or other general business purposes, require us to use a substantial portion of our cash flow from operations to make debt service payments, limit our flexibility to plan for, or react to, changes in our business and industry, place us at a competitive disadvantage compared to our less leveraged competitors and increase our vulnerability to the impact of adverse economic and industry conditions.Additionally, under the Notes, if we undergo a "fundamental change," subject to certain conditions, holders may require us to repurchase for cash all or part of their Notes at a fundamental change repurchase price equal to 100% of the principal amount of the Notes to be repurchased, plus accrued and unpaid interest, and if we undergo a "make-whole fundamental change", the conversion rate for the Notes may be increased. These outcomes may, in certain circumstances, delay or prevent a takeover of us that might otherwise be beneficial to our stockholders.

We are exposed to various credit risks.

We rely on cross-currency swap contracts to effectively manage our currency risk related to our Senior Unsecured Bonds - Series 4 issued in July 2020. Failure of any of our counterparties to perform under derivatives contracts could disrupt our hedging operations if the counterparties do not fulfill their obligations under the agreements, particularly if we were entitled to a termination payment under the terms of the contract that we did not receive, if we had to make a termination payment upon default of the counterparty, or if we were unable to reposition the swap with a new counterparty. We are also subject to counterparty risk under the capped call transactions entered into in connection with the Notes. If an option counterparty becomes subject to insolvency proceedings, we will become an unsecured creditor with a claim equal to our exposure at the time under the capped call transactions with such option counterparty. Our exposure will depend on many factors but, generally, an increase in our exposure will be correlated to an increase in the market price and in the volatility of our common stock. A default by an option counterparty may also cause adverse tax consequences and dilution in the value our common stock.

We may not be able to obtain sufficient insurance coverage to cover damages to our assets and profitability.

We maintain physical damage and business interruption insurance. However, our business interruption and property damage insurance coverage may not be sufficient to cover all losses sustained as a result of natural disasters such as flood, volcanic eruptions, lava flows, wind and earthquake or any other insurable risk. In addition, insurance coverage may not continue to be available in the future at rates that we believe are reasonable or in amounts of coverage or with scope of coverage adequate to insure against future natural disasters. Following the May 2018 eruption of the Kilauea volcano in Hawaii, the full amount of our insurance claim for damages to our Puna power plant was denied and we experienced increased costs and difficulties in obtaining sufficient insurance coverage for natural disasters. Before the eruption in 2018, we obtained natural disasters business interruption and property damage insurance coverage of up to approximately $100 million compared to $30 million, with portions of the risk self-insured. An inability to obtain sufficient and adequate

insurance to cover all book net equity may cause us to self-insure some or all of a particular location and losses, causing us to experience higher than expected insurance costs.

If insurance premiums or deductibles were to increase in the future, if certain types of insurance coverage were to become unavailable or cost prohibitive, if we were to have to increase the percentage of our self-insured insurance coverage or if we were to experience losses in excess of, or outside the scope of, our insurance coverage, such additional costs could have a material adverse effect on our business, financial condition, results of operations and cash flows.

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, including public health issues, such as epidemics, pandemics, and other outbreaks, as well events such as fires, explosions, earthquakes, landslides, floods, severe storms, volcanic eruptions, lava flow or other similar events. Any of these events could result in a shutdown of certain of our businesses. 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.

In addition to our power plant in Puna, Hawaii, our power plant in Amatitlan, Guatemala is located in proximity to an active volcano. 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.

Threats of terrorism and other disasters may impact our operations in unpredictable ways and could adversely affect our business, financial condition, future results and cash flow.

Our operations and facilities, in particular, our generation and transmission facilities, information technology systems and other infrastructure facilities, systems and physical assets that we acquire, construct or develop, as well as those of third parties on which we rely, may be targets of terrorist acts and threats, as well as events occurring in response to or in connection with them, that could cause environmental repercussions, result in full or partial disruption of our operations. These operations and facilities are also subject to natural disasters, public health crises, fire, power loss and telecommunication failures. Any of our assets or those of third-party vendors could be directly or indirectly affected by such events or activities. Any such terrorist acts, environmental repercussions or disruptions or natural disasters could result in a significant decrease in revenues or significant reconstruction or remediation costs, beyond what could be recovered through insurance policies, which could have a material adverse effect on the business, financial condition, results of operations and cash flows.

Risks Related to Ownership of Our Common Stock

Future equity issuances, including through our current or any future equity compensation plans, could result in dilution, which could cause the price of our shares of common stock to decline.

We may issue additional shares of our common stock in the future pursuant to current or future equity compensation plans, upon conversions of preferred stock or debt, or in connection with future acquisitions or financings. Issuances under convertible instruments that are already outstanding, such as the Notes, may be outside of our control, and conversions to the extent allowed under these instruments may be more attractive to investors during sustained periods when our common stock price exceeds the conversion price. We may also seek to raise additional funds, finance acquisitions or develop strategic relationships by issuing additional shares of our common stock. If we choose to raise capital by selling shares of our common stock, or securities convertible into shares of our common stock, or additional shares are issued for the reasons described above or otherwise, the issuance could have a dilutive effect on the holders of our common stock and could have a material negative effect on the market price of our common stock.

The price of our common stock has in the past and may in the future fluctuate substantially, and your investment may decline in value.

The market price of our common stock has in the past and may in the future 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;
- under the capped call transactions we entered into in connection with the Notes, modifications by the option counterparties or their affiliates of their hedge positions which cause them to enter into or unwind derivatives in our common stock or purchase or sell our common stock or other securities;
- the trading of our common stock on multiple trading markets, which takes place in different currencies and at different times; and
- general economic conditions.

In addition, the stock market in general, and the NYSE and the market for energy companies in particular, have experienced extreme price and volume fluctuations that have often been unrelated or disproportionate to the operating performance of particular companies affected. These broad market and industry factors may materially harm the market price of our common stock, regardless of our operating performance. In the past, following periods of volatility in the market price of a company's securities, securities class-action litigation has often been instituted against that company. Such litigation, if instituted against us could result in substantial costs and a diversion of management's attention and resources, which could materially harm our business, financial condition, future results and cash flow. We are generally obliged under our bylaws, to the extent permitted under Delaware law, to indemnify our current and former officers who are named as defendants in these types of lawsuits. While a certain amount of insurance coverage is available for expenses or losses associated with these lawsuits, this coverage may not be sufficient for certain litigation. For information on our recently dismissed and ongoing securities class actions, see "Commitments and Contingencies" in Note 20 to the consolidated financial statements contained in Item 8 of this Annual Report.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 1C. CYBERSECURITY

Risk management and strategy

We prioritize the management of cybersecurity risk and the protection of information across our enterprise by embedding data protection and cybersecurity risk management in our operations. Our processes for assessing, identifying, and managing material risks from cybersecurity threats have been integrated into our overall risk management system and processes.

As a foundation of this approach, our privacy and security policies govern our business lines and subsidiaries. We monitor the privacy and security regulations applicable to us in the regions where we do business as well as proposed privacy and security regulations and emerging risks.

We conduct internal and external penetration testing and risk assessments on a regular basis, and have engaged consultants, auditors and other relevant third parties to assist us with cybersecurity risk management processes. Our operations rely on the secure processing, storage and transmission of confidential and other information in our computer systems and networks. Computer viruses, hackers, and employee or vendor misconduct, and other external hazards could expose our data systems and those of our vendors to security breaches, cybersecurity incidents or other disruptions, any of which could materially and adversely affect our ability to conduct our business. While we have experienced cybersecurity incidents, to date, we are not aware that we have experienced a material cybersecurity incident. The sophistication of cybersecurity threats continues to increase, and the controls and preventative actions we take to reduce the risk of cybersecurity incidents and protect our systems, including the regular testing of our cybersecurity incident response plan, may be insufficient. In addition, new technology that could result in greater operational efficiency may further expose our computer systems to the risk of cybersecurity incidents. We may also maintain cyber liability insurance that covers certain damages caused by cybersecurity 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 cybersecurity incident will be covered by insurance or recoverable in rates.

For more information, see Part I of this Annual Report, Item 1A "Risk Factors—Risks Related to the Company's Business and Operation—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."

Governance

As part of our overall risk management approach, we prioritize the management of cybersecurity risk at several levels, including Board oversight, executive commitment and employee training. Our Audit Committee, comprised fully of independent directors from our Board, oversees the Board's responsibilities relating to cybersecurity risks. Each of our Audit Committee and Board is informed of such risks through reports from our Chief Information Officer ("CIO") at least twice per year.

Our Chief Information Security Officer ("CISO"), who has been a chief information security officer at Ormat for eight years, is certified by the International Information System Security Certification Consortium as an Information Systems Security Management Professional ("ISSMP"), as an Information Systems Security Architecture Professional ("ISSAP"), and as a Certified Information Systems Security Professional ("CISSP"). Our CISO oversees compliance of our information security ("IS") standards and mitigation of IS risks. We also have the following internal bodies to support our processes to assess and manage cybersecurity risk as follows:

- The Crisis Incident Management Team, which includes members of the executive management team, the CIO, CISO, and other senior executives across the Company, is alerted as appropriate to cybersecurity incidents, as well as other crises, such as natural disasters and outages. This team also periodically oversees tabletop drills on various cybersecurity incidents.
- The Cyber Risk Disclosure Committee brings together senior management, including the CEO, CFO, General Counsel and other relevant functions to review the materiality of cyber incidents for disclosure purposes. The Cyber Risk Disclosure Committee members are also part of the Crisis Incident Management team.
- The IT leadership team, led by our Chief Information Officer, oversees IT initiatives while considering cybersecurity risk mitigation with respect to these initiatives. The team provides periodic presentations to senior management and the Board on cybersecurity risk and mitigation.
- The VP of Technical and Maintenance chairs monthly cybersecurity meetings to review cyber risks or threats related to the operations of our geothermal projects.

At the level of the general employee population, we hold trainings on privacy and information security, records and information management, and information security regulatory compliance, conduct phishing tests and generally seek to promote awareness of cybersecurity risk through broad communication and educational initiatives, depending on the employee's level, role and exposure to sensitive systems and the associated cybersecurity risk profile. We also contract with an external vendor to monitor alerts in real time on cybersecurity incidents.

With respect to third party service providers, we obligate our vendors to adhere to privacy and cybersecurity measures. We also restrict vendors' access to our organizational systems through a segmented and controlled environment, which is monitored by us, and perform detailed and customized risk assessments of certain vendors, including their ability to protect data from unauthorized access.

ITEM 2. PROPERTIES

Our main corporate offices are located at 6884 Sierra Center Drive in Reno, Nevada 89511 in the U.S, which property we currently own. 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 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".

ITEM 3. LEGAL PROCEEDINGS

The information required with respect to this item can be found under "Commitments and Contingencies" in Note 20 of the consolidated financial statements contained in Item 8 of this Annual Report and is incorporated by reference herein.

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*

Market for Our Common Stock

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.

Record Holders

As of February 25, 2026, there were 14 record holders of our common stock, including Cede & Co., the nominee of the Depository Trust Company. The number of record holders may not be representative of the number of beneficial owners of our common stock, whose shares are held in street name by banks, brokers and other nominees.

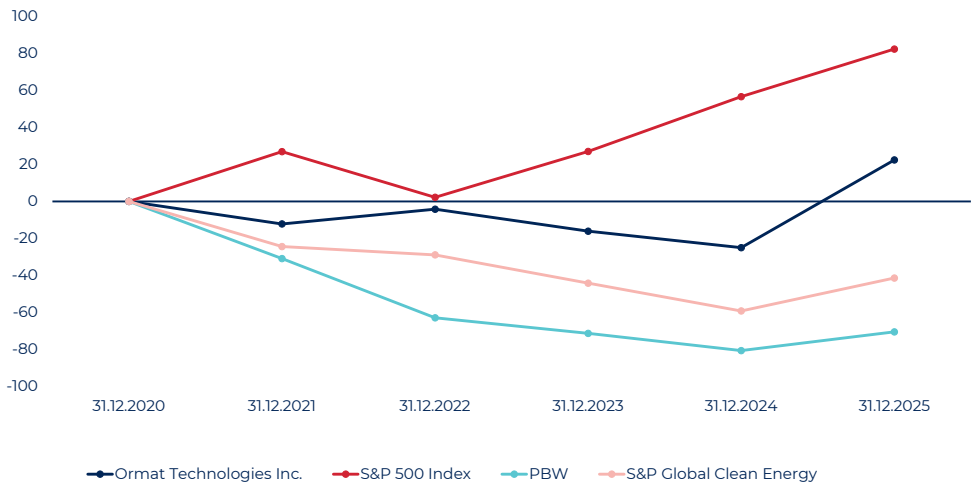
Dividend Policy

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

Stock Performance Graph

The following performance graph represents the cumulative total shareholder return for the period December 31, 2020 through December 31, 2025 for our common stock, compared to the Standard and Poor's Composite 500 Index, S&P Global Clean Energy Index and PBW - Invesco WilderHill Clean Energy ETF. We have also provided the data in the format of a chart under the graph for ease of reference. The data assumes that $100 was invested at the market close on December 31, 2020 in our common stock, the Standard and Poor's Composite 500 Index, the S&P Global Clean Energy Index and the PBW - Invesco WilderHill Clean Energy ETF, and assumes reinvestments of dividends, if any. The stock price performance on this graph is not necessarily indicative of future performance. On February 25, 2026, the closing price of our common stock as reported on the NYSE was $117.06 per share.

Comparison of Cumulative Returns (%) for the Period December 31, 2020 through December 31, 2025



	2021	2022	2023	2024	2025
Ormat Technologies, Inc	(12.2)%	(4.2)%	(16.1)%	(25.0)%	22.4 %
Standard & Poor's Composite 500 Index	26.9 %	2.2 %	27.0 %	56.6 %	82.3 %
PBW - Invesco WilderHill Clean Energy ETF	(30.9)%	(62.9)%	(71.3)%	(80.6)%	(70.5)%
S&P Global Clean Energy Index	(24.4)%	(28.9)%	(44.2)%	(59.2)%	(41.4)%

Equity Compensation Plan Information

For information on our equity compensation plan, see "Part III, Item 12 Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters".

Issuer Purchases of Equity Securities

None.

Sales of Unregistered Equity Securities

None.

ITEM 6. *[RESERVED]*

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

Recent Developments

The most significant recent developments for our Company and business during 2025 and 2026 to date are described below:

- In February 2026, we entered into a long-term geothermal portfolio PPA to supply up to 150MW of new geothermal capacity to support Google's data center's energy needs, through NV Energy's Clean Transition Tariff program. The portfolio structure is expected to enable the development of multiple new geothermal projects across Nevada, with energy deliveries anticipated to commence between 2028 and 2030 as projects reach commercial operations. Per the PPA structure, the contract term begins with the first geothermal project achieving commercial operations and extends 15 years beyond the final project's commercial operations date. The agreement and related energy supply arrangements are subject to approval by the Nevada PUC, which is expected in the second half of 2026.
- In January 2026, we acquired Hoku, a recently built operational solar-plus-storage facility on the Big Island of Hawaii, from Innergex Renewable Energy Inc. for total cash consideration of $80.5 million. The acquired assets include a 30MW solar PV facility paired with a 30MW/120MWh battery energy storage system, which achieved commercial operation in March 2025 and is fully operational. All output from the facility is sold under a 25-year fixed-price power purchase agreement with HECO.
- In January 2026, we made a $25 million investment in Sage Geosystems Inc. ("Sage") as part of Sage's Series B financing round. This investment represents an important milestone in our strategy to expand our EGS portfolio and capabilities and supports the continued development and commercialization of next-generation geothermal technology. In August 2025, we also announced the signing of a strategic commercial agreement with Sage. Under the terms of the agreement, Sage will pilot its advanced pressure geothermal technology to extract geothermal heat energy from hot dry rock at an existing Ormat power plant. This collaboration aims to significantly reduce the time needed to bring geothermal energy to market and is expected to enhance the Company's operational efficiency while accelerating the implementation of next-generation geothermal solutions. The strategic commercial agreement was closed.
- In January 2026, we were awarded the Telaga Ranu geothermal working area concession in Indonesia following a competitive tender process. The concession is located in Halmahera, North Maluku, within one of Indonesia's highest approved feed-in tariff zones and has the potential to support up to approximately 40MW of baseload geothermal generation capacity. This award strengthens our long-term development pipeline and supports our continued growth strategy in Indonesia.
- In January 2026, we entered into a new 20-year PPA with Switch, Inc., a leading provider of data center infrastructure, pursuant to which Switch will purchase approximately 13MW of carbon-free geothermal capacity from our Salt Wells geothermal power plant located near Fallon, Nevada. Under the agreement, energy deliveries are scheduled to commence in the first quarter of 2030, following the completion of a planned major upgrade to the Salt Wells facility. As part of the agreement, we also have the option to further expand the facility's output through the addition of an approximately 17MW solar PV facility to support the plant's auxiliary power needs.
- In December 2025, we reached the COD for Arrowleaf, our first hybrid solar-plus-storage project, consisting of approximately 42MW of solar generation capacity and 35MW/140MWh of energy storage. The project operates

under a long-term tolling agreement with San Diego Community Power. In connection with the project's COD, the related hybrid tax equity partnership transaction with Morgan Stanley Renewables, Inc. closed in December 2025 and resulted in approximately $38 million of upfront proceeds to the Company.

- In October 2025, the Company and SLB announced an agreement to fast-track the development and commercialization of integrated geothermal assets, including EGS. Together, Ormat and SLB intend to streamline project deployment, from concept to power generation. As part of this effort, SLB will develop, pilot and scale EGS solutions to enable wide-scale EGS adoption. This collaboration will include the design and construction of an EGS pilot at an Ormat site.
- In September 2025, we successfully commenced the commercial operations of our 60MW/120MWh Lower Rio energy storage facility, located in Texas.
- In August 2025, we signed two Geothermal Exploration and Energy Conversion Agreements ("GEECA"), a novel form of power purchase agreement, with Perusahaan Listrik Negara ("PLN"), each covering up to 20 MW of geothermal capacity each in Songa Wayaua and Atadei located in Indonesia. Under the terms of these agreements, the Company, through its project companies, will undertake the exploration drilling, financing, designing, constructing, installing, and operating the Geothermal Power Plant on a BOT ("Build, Operate and Transfer") basis , with a 23 year operating term. PLN will reimburse the cost of successful drilling and retains the option to acquire up to a 30% equity interest in the project companies.
- In August 2025, we announced the signing of a 25-year extension to our existing power purchase agreement with SCPPA, for the 52MW from Heber 1 geothermal facility. This long-term agreement, which is effective February 2026, will ensure the continued delivery of clean, baseload geothermal energy to the Los Angeles Department of Water and Power and the Imperial Irrigation District. The Company will supply the SCPPA with electricity from the Ormat Heber 1 geothermal facility, located in the Imperial Valley of Southern California.
- In July 2025, we entered into loan agreements with a consortium of French banks pursuant to which we will borrow up to approximately €99.8 million aggregate principal amount in connection with our new Bouillante geothermal power plant in Guadeloupe.
- In July 2025, we entered into a tax partnership agreement with a private investor, under which the private investor paid approximately $77.1 million for the tax benefits related to the Heber 1&2 Geothermal power plants that are part of our Heber Complex. The private investor will pay over eight years additional installments that are expected to amount to approximately $25.7 million.
- In June, 2025, we entered into loan agreements with the Caribbean Development Bank and Caricom Development Fund pursuant to which we will borrow up to $49.8 million aggregate principal amount in connection with the 10MW Geothermal Project in Dominica.
- In June 2025, we closed the acquisition of the Blue Mountain geothermal power plant from Cyrq Energy. The 20MW facility, located in Humboldt County, NV, was purchased for $88.7 million for 100% of the equity interest in the power plant. The power plant, built using Ormat technology, features an existing 51MW interconnection capacity and a PPA with NV Energy that expires at the end of 2029. The Company plans to upgrade the power plant and increase its capacity by 3.5MW. Additionally, subject to permit and PPA approval, Ormat intends to add a 13MW solar facility to support the plant's auxiliaries.
- In May 2025, we announced the signing of a $62.0 million Hybrid Tax Equity partnership with Morgan Stanley Renewables, Inc. The partnership's transaction covers the Lower Rio 60MW/120MWh storage facility and the Arrowleaf 35MW/140MWh storage and 42MW solar projects, which are expected to achieve COD by the end of 2025.
- In February 2025, we won a tender issued by the Israeli Electricity Authority and have been awarded two separate 15-year tolling agreements for two Energy Storage facilities. The facilities under the tolling agreements are expected to have a combined capacity of approximately 300MW/1200MWh. The ownership of the projects will be shared, 50/50 between Ormat and Allied Infrastructure LTD, a leading infrastructure company in Israel.
- In February 2025, we announced the successful COD for the Ijen geothermal power plant that is owned jointly with PT Medco Power Indonesia ("Medco Power"). The Ijen Geothermal Power Plant, equipped with Ormat Energy Converter, began operations with its first phase, delivering 35MW of electricity power to the Java grid, Ormat's share of the facility is 17MW.
- In January 2025, we announced the signing of a 10-year PPA with Calpine Energy Solutions, one of North America's largest energy suppliers. Under this agreement, Calpine Energy Solutions agreed to purchase up to 15MW of clean, renewable energy from the Mammoth 2 geothermal power plant located near Mammoth Lakes, California, to support demand within its retail portfolio. Energy deliveries under the PPA are scheduled to begin

in the first quarter of 2027 and will replace the existing PPA with Southern California Edison. The new PPA includes an increase in production capacity and a higher price point.

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:

- **Increased Demand for Baseload and Data Centers:** Demand for electricity generated from geothermal and other renewable resources in the United States has increased due to the need for reliable baseload power and the growing energy requirements of data centers. This demand is supported by legislative and regulatory initiatives, including state RPS and clean energy mandates, which encourage or require the procurement of renewable energy.
- **Higher PPA Pricing in the United States:** Increasing electricity demand from data centers and hyperscale customers has contributed to higher PPA pricing in the United States for new geothermal projects and for the renewal of PPAs scheduled to expire over the next few years. This trend may support improved profitability and increased future revenues from our operating assets; however, actual outcomes will depend on market conditions, and timing of contract renewals.
- **Enhanced Geothermal Systems ("EGS") Opportunities:** Advancements in and viability of EGS technology may create opportunities for growth in both our Electricity and Product segments by expanding the range of geothermal resources that can be economically developed. EGS has the potential to enable power generation and equipment sales in locations that do not have naturally occurring hydrothermal resources, which could increase the addressable market for geothermal energy. The timing, scale and commercial viability of EGS development remain uncertain and will depend on technological progress, regulatory frameworks, capital availability and market conditions.
- **Reduced Tolling prices for Storage Facilities in Texas:** While tolling agreements for storage facilities were introduced in Texas, prices of new tolling arrangements has declined, and certain previously executed tolling agreements were cancelled. This shift is primarily driven by sustained low merchant power prices, which have reduced the economic attractiveness of tolling structures and increased exposure to merchant market volatility for storage projects.
- **Local Support:** 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.
- **Product Segment Opportunities and Competition:** In the Product segment, we believe there are new business opportunities in the U.S., Asia Pacific, New Zealand 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 lead to further reductions in the prices that we are able to charge for our binary equipment.
- **OBBBA Impact:** On July 4, 2025, the OBBBA was signed into law by the President of the United States. Rules under the OBBBA were updated in August 2025. For more information, see Note 16 to the consolidated financial statements contained in this annual report. The Company is currently evaluating the impact of the OBBBA on its consolidated financial statements, however, it does not expect the impact to be material.
- **New Tariffs:** Throughout 2025, the United States introduced actions to increase import tariffs at various rates, including on certain products imported from almost all countries and individualized higher tariffs on certain other countries, such as China. Other countries have announced retaliatory actions or plans for retaliatory actions in response. Some of these tariff announcements were followed by limited exemptions and temporary pauses. As of the date of this annual report, discussions remain ongoing regarding U.S. trade restrictions and tariffs on imports

and retaliatory tariffs from numerous countries, and while certain of these tariffs and other trade restrictions have already taken effect, there continues to be significant uncertainty about the future relationship between the United States and other countries regarding such trade policies, treaties, and tariffs. Accordingly, we can make no assurance about the eventual impact on our operating results and business. Our Energy Storage segment growth relies on imported batteries from China, and the growth of projects in the United States in the Electricity segment requires raw materials and equipment from various countries.

While there has so far been only limited impact on short-term growth in both of these segments, a significant increase in tariffs may lead to a slowdown in the growth of our Energy Storage segment in the United States if we are unable to pass the price increases from tariffs through to our customers. This could affect our long-term growth targets, specifically in our Energy Storage segment in the United States, and, to a lesser extent, across our business. Additionally, increases in the cost of raw materials and equipment resulting from tariffs could increase our capital expenditures for projects built in the United States under our Electricity segment. We have worked to accelerate imports into the United States and have expedited Chinese imports prior to the potential reinstatement of higher tariffs. However, we can make no assurance that we will succeed in avoiding any of these negative consequences. In addition, current uncertainties about tariffs and their effects on trading relationships may contribute to inflation in the markets in which we operate. For more information, see Part II, Item 1A "Risk Factors"

- **Inflation and Macroeconomic Trends:** Higher rates of inflation, particularly in the U.S., have been observed over the last few years. While most international-based contracts are indexed to inflation, U.S. contracts are not. Although we see a moderation in the rate of inflation, if inflation continues to rise, it may increase expenses and impact profit margins. Additionally, macroeconomic trends, including a potential economic recession, changes in Federal Reserve monetary policy, the policies of the new presidential administration, and geopolitical risks, including ongoing Middle East tensions, may adversely affect our operations and financial condition.

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; and the sale of energy storage services and electricity from our operating energy storage facilities.

Electricity Segment

Revenues attributable to our Electricity segment are derived from the sale of electricity from our power plants pursuant to long-term PPAs. While approximately 93.8% of our Electricity revenues for the year ended December 31, 2025 were derived from PPAs with fixed price components, we have a variable price PPA in Hawaii, which provide for payments based on the local utilities' avoided cost. The avoided cost is the incremental cost that the power purchaser avoids by not having to generate such electrical energy itself or purchase it from others. In Hawaii, the prices paid for electricity pursuant to the 25 MW PPA for the Puna Complex change primarily as a result of variations in the price of oil as well as other commodities. Accordingly, our revenues from this power plant may fluctuate. In 2024, the HPUC approved a new PPA related to Puna with fixed prices, increased capacity and an extension of the term until 2052, which we expect to be in effect in early 2027. 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. Energy payments are payments calculated based on the amount of electrical energy delivered to the relevant power purchaser at a designated delivery point. Our most 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.

Product Segment

Revenues attributable to our Product segment are based on the sale of equipment, engineering, procurement and construction contracts and the provision of various services to our customers. Product segment revenues 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.

Energy Storage Segment

Revenues attributable to our Energy Storage segment are generated by several grid-connected BESS facilities that we own and operate from selling energy, capacity and/or ancillary services in merchant markets like PJM Interconnect, ISO New England, ERCOT and CAISO or under tolling agreements that have fixed revenues. The revenues fluctuate over time since a large portion of such revenues are generated in the merchant markets, where price volatility is inherent. We are seeking to reduce volatility by increasing the amount of long-term tolling agreements in our portfolio. In the two solar PV plus energy storage facilities, although the solar capacity is included in the Electricity Segment portfolio, 100% of the revenues are recorded under the Energy Storage segment.

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 fixed contracts with load serving entities, investor-owned utilities, publicly owned utilities and community choice aggregators.

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, and revenues and costs actually incurred to complete customer orders compared to the costs originally budgeted for such orders. We evaluate our Energy Storage segment performance similar to the Electricity segment with respect to projects that we own and operate.

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

	Revenues			% of Total Revenues		
	Year Ended December 31,			Year Ended December 31,		
	2025	2024	2023	2025	2024	2023
Revenues:	(Dollars in thousands)					
Electricity	$ 693,900	$ 702,264	$ 666,767	70.1 %	79.8 %	80.4 %
Product	216,686	139,661	133,763	21.9	15.9	16.1
Energy Storage	78,957	37,729	28,894	8.0	4.3	3.5
Total revenues	$ 989,543	$ 879,654	$ 829,424	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 segments for the years indicated:

	Revenues			% of Total Revenues		
	Year Ended December 31,			Year Ended December 31,		
	2025	2024	2023	2025	2024	2023
Electricity Segment:	(Dollars in thousands)					
United States	$ 500,377	$ 510,645	$ 473,323	72.1 %	72.7 %	71.0 %
International	193,523	191,619	193,444	27.9	27.3	29.0
Total	$ 693,900	$ 702,264	$ 666,767	100.0 %	100.0 %	100.0 %

Product Segment:						
United States	$ 10,954	$ 8,969	$ 7,610	5.1 %	6.4 %	5.7 %
International	205,732	130,692	126,153	94.9	93.6	94.3
Total	$ 216,686	$ 139,661	$ 133,763	100.0 %	100.0 %	100.0 %
Energy Storage Segment:						
United States	$ 78,957	$ 37,729	$ 28,894	100.0 %	100.0 %	100.0 %
International	—	—	—	—	—	—
Total	$ 78,957	$ 37,729	$ 28,894	100.0 %	100.0 %	100.0 %

In 2025, 2024 and 2023, 40%, 37% and 39% of our total revenues were derived from foreign locations, respectively, and our foreign operations had higher gross margins than our U.S. operations in each of those years. A substantial portion of the Electricity Segment foreign revenues came from Kenya and, to a lesser extent, from Honduras, Guadeloupe, and Guatemala. 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, as summarized below.

Electricity Segment

Our Electricity segment domestic revenues were approximately 72%, 73% and 71% of our total Electricity segment for the years ended December 31, 2025, 2024 and 2023, respectively. However, domestic operations have higher costs of revenues and expenses than our foreign operations. 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. Our power plants in foreign locations 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 2025 and 2024, our foreign operations of the segment accounted for 39% and 39% of our total gross profits, 49% and 48% of our net income (considering the majority of corporate operating and financing expenses are recorded under our domestic operations), and 29% and 31% of our EBITDA, respectively.

Product Segment

Our Product segment foreign revenues were 95%, 94% and 94% of our total Product segment revenues for the years ended December 31, 2025, 2024 and 2023, respectively.

Energy Storage Segment

Our Energy Storage segment domestic revenues were 100.0% of our total Energy storage segment revenues for years ended December 31, 2025, 2024 and 2023, respectively.

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 as 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 Mammoth Complex and the North Brawley power plant in California, the Raft River power plant in Idaho, the Neal Hot Springs power plant in Oregon and Dixie Valley power plant in Nevada, 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 and gross profit in the winter months to be higher than the revenues and gross profit in the summer months and in general we expect the first and fourth quarters to generate higher revenues than the second and third quarters. In the Storage segment pursuant to the Bottleneck tolling agreement, approximately 45% of the revenues are generated in the third quarter, and the rest is roughly even between the first, second and fourth quarters.

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 4.5% and 4.6% of Electricity segment revenues for the years ended December 31, 2025 and 2024, 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 Segment

The principal cost of revenues attributable to our Energy Storage segment are direct costs of the BESS that we own, and depreciation and amortization. Direct costs include the labor associated with operations and maintenance of owned BESS. In addition, the cost of revenue includes insurance and property tax expenses.

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 critical accounting estimates and assumptions to our policies, 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 estimates 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 revenue and gross margin. 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 delivered as the customer obtains control of the asset, as applicable.

Electricity 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 15 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. 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 $286.9 million and $193.7 million at December 31, 2025 and 2024, respectively.

Impairment of Long-Lived Assets and Long-Lived Assets to be Disposed of

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

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

Recoverability of assets to be held and used is measured by a comparison of the carrying amount of an asset to the estimated future net undiscounted cash flows expected to be generated by the asset. The significant assumptions that we use in estimating our undiscounted future cash flows include (i) projected generating capacity of the power plant and rates to be received under the respective PPA and (ii) projected operating expenses of the relevant power plant. Estimates of future cash flows used to test recoverability of a long-lived asset under development also include cash flows associated with all future expenditures necessary to develop the asset. If future cash flows are actually less than those 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, 2025, no impairment exists for any of our long-lived assets; however, estimates as to the recoverability of such assets may change based on revised circumstances.

Estimates of the fair value of assets require estimating useful lives and selecting a discount rate that reflects the risk inherent in future cash flows.

Obligations Associated with the Retirement of Long-Lived Assets

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

Accounting for Income Taxes

Significant estimates are required to arrive at our consolidated income tax provision. This process requires us to estimate our actual current tax exposure and to make an assessment of temporary differences resulting from different 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 a valuation allowance. In assessing the need for a valuation allowance, we estimate future taxable income, including the impacts of the enacted tax law, the feasibility of ongoing tax planning strategies and the realizability 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. In the future, if there is insufficient evidence that we will be able to generate sufficient future taxable income in the U.S., we may be required to record a valuation allowance, resulting in income tax loss in our Consolidated Statement of Operations.

In the ordinary course of business, there can be 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 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,		
	2025	2024	2023
	(Dollars in thousands, except earnings per share data)		
Revenues:			
Electricity	$ 693,900	$ 702,264	$ 666,767
Product	216,686	139,661	133,763
Energy Storage	78,957	37,729	28,894
Total revenues	989,543	879,654	829,424

Cost of revenues:			
Electricity	495,989	459,526	422,549
Product	170,671	113,911	115,802
Energy storage	50,198	33,598	27,055
Total cost of revenues	716,858	607,035	565,406
Gross profit			
Electricity	197,911	242,738	244,218
Product	46,015	25,750	17,961
Energy storage	28,759	4,131	1,839
Total gross profit	272,685	272,619	264,018
Operating expenses:			
Research and development expenses	6,304	6,501	7,215
Selling and marketing expenses	18,898	17,694	18,306
General and administrative expenses	79,592	80,119	68,179
Other operating income	(14,844)	(9,375)	—
Impairment of long-lived assets	12,064	1,280	—
Write-off of unsuccessful exploration and storage activities	1,446	3,930	3,733
Operating income	169,225	172,470	166,585
Other income (expense):			
Interest income	6,015	7,883	11,983
Interest expense, net	(141,851)	(134,031)	(98,881)
Derivatives and foreign currency transaction gains (losses)	5,248	(4,187)	(3,278)
Income attributable to sale of tax benefits	66,726	73,054	61,157
Other non-operating income (expense), net	385	188	1,519
Income from operations before income tax and equity in earnings (losses) of investees	105,748	115,377	139,085
Income tax (provision) benefit	20,282	16,289	(5,983)
Equity in earnings (losses) of investees	960	(425)	35
Net Income	126,990	131,241	133,137
Net income attributable to noncontrolling interest	(3,092)	(7,508)	(8,738)
Net income attributable to the Company's stockholders	$ 123,898	$ 123,733	$ 124,399
Earnings per share attributable to the Company's stockholders:			
Basic:	$ 2.04	$ 2.05	$ 2.09
Diluted:	$ 2.02	$ 2.04	$ 2.08
Weighted average number of shares used in computation of earnings per share attributable to the Company's stockholders:			
Basic	60,705	60,455	59,424
Diluted	61,362	60,790	59,762

Results as a percentage of revenues

	Year Ended December 31,		
	2025	**2024**	**2023**
Revenues:			
Electricity	70.1 %	79.8 %	80.4 %
Product	21.9	15.9	16.1
Energy storage	8.0	4.3	3.5
Total revenues	100.0	100.0	100.0

Cost of revenues:			
Electricity	71.5	65.4	63.4
Product	78.8	81.6	86.6
Energy storage	63.6	89.1	93.6
Total cost of revenues	72.4	69.0	68.2
Gross profit (loss):			
Electricity	28.5	34.6	36.6
Product	21.2	18.4	13.4
Energy storage	36.4	10.9	6.4
Total gross profit	27.6	31.0	31.8
Operating expenses:			
Research and development expenses	0.6	0.7	0.9
Selling and marketing expenses	1.9	2.0	2.2
General and administrative expenses	8.0	9.1	8.2
Other operating income	(1.5)	(1.1)	0.0
Impairment of long-lived assets	1.2	0.1	0.0
Write-off of unsuccessful exploration and storage activities	0.1	0.4	0.5
Operating income	17.1	19.6	20.1
Other income (expense):			
Interest income	0.6	0.9	1.4
Interest expense, net	(14.3)	(15.2)	(11.9)
Derivatives and foreign currency transaction gains (losses)	0.5	(0.5)	(0.4)
Income attributable to sale of tax benefits	6.7	8.3	7.4
Other non-operating income (expense), net	—	—	0.2
Income from continuing operations before income tax and equity in earnings (losses) of investees	10.7	13.1	16.8
Income tax (provision) benefit	2.0	1.9	(0.7)
Equity in earnings (losses) of investees	0.1	—	—
Net Income	12.8	14.9	16.1
Net income attributable to noncontrolling interest	(0.3)	(0.9)	(1.1)
Net income attributable to the Company's stockholders	12.5 %	14.1 %	15.0 %

Comparison of the year ended December 31, 2024 and the year ended December 31, 2023

A discussion of changes in our results of operations in 2024 compared to 2023 has been omitted from this Form 10-K, but may be found in “Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations” of our Form 10-K for the fiscal year ended December 31, 2024, filed with the SEC on February 27, 2025, which is incorporated by reference herein. This Form 10-K for the fiscal year ended December 31, 2024 is available free of charge on the SECs website at www.sec.gov and at www.Ormat.com, by clicking “Investors” located at the top of the home page.

Comparison of the Year Ended December 31, 2025 and the Year Ended December 31, 2024

Total Revenues

	Year Ended December 31, 2025	Year Ended December 31, 2024	Increase (Decrease)	
	(Dollars in millions)			
Electricity segment revenues	$ 693.9	$ 702.3	$ (8.4)	(1.2) %
Product segment revenues	216.7	139.7	77.0	55.2

Energy Storage segment revenues	79.0	37.7	41.2	109.3
Total Revenues	**$ 989.5**	**$ 879.7**	**$ 109.8**	**12.5 %**

For the year ended December 31, 2025, our total revenues increased by 12.5% from $879.7 million in 2024 to $989.5 million in 2025. For the year ended December 31, 2025, our Electricity segment generated 70.1% of our total revenues, compared to 79.8% in the previous year, while our Product segment generated 21.9% of our total revenues, compared to 15.9% in the previous year, and our Energy Storage segment generated 8.0% of our total revenues, compared to 4.3% in the previous year.

Electricity Segment

Revenues attributable to our Electricity segment for the year ended December 31, 2025 were $693.9 million, compared to $702.3 million for the year ended December 31, 2024, representing a 1.2% decrease. This decrease of $8.4 million was mainly attributable to (i) a decrease of $18.6 million related to curtailments in the U.S., mainly from McGinness Hills, Mammoth, Tungsten and Dixie Valley; (ii) a decrease of $13.9 million as a result of a temporary reduction in generation in our Puna power plant, primarily related to wellfield issues and lower energy rates in 2025 compared to 2024; (iii) a decrease of $3.2 million related to the Stillwater power plant, primarily due to planned repowering of the power plant; and (iv) an additional reduction in revenues in lower amounts at a number of other power plants. This decrease in revenues was partially offset by the following increases in revenues: (i) an increase of $6.6 million related to the Blue Mountain power plant which was purchased in June 2025; (ii) an increase of $5.4 million related to the Beowawe repower project which commenced commercial operation in the second quarter of 2024; (iii) an increase of $8.9 million in the Dixie Valley power plant, net of curtailment, due to the unscheduled maintenance work in 2024; and (iv) additional increases in revenues in lower amounts at a number of other power plants, primarily in Kenya and Cove Fort in the amount of $5.7 million.

During the years ended December 31, 2025 and 2024, our consolidated power plants generated 7,493,287 MWh and 7,450,071 MWh, respectively, an increase of 0.6%. The generation in 2025 and 2024 was lower by 277,923 MWh and 121,299 MWh, respectively due to curtailments in our U.S. projects. The average prices during the years ended December 31, 2025 and 2024 were $92.6, and $94.3 per MWh, respectively, mainly due to Puna's lower generation and energy rate.

Product Segment

Revenues attributable to our Product segment for the year ended December 31, 2025 were $216.7 million, compared to $139.7 million for the year ended December 31, 2024, representing a 55.2% increase. The increase is primarily related to the progress in our projects and timing of when revenues are recognized. During 2025 and 2024, Product revenues included projects primarily in New Zealand and Dominica.

Energy Storage Segment

Revenues attributable to our Energy Storage segment for the year ended December 31, 2025 were $79.0 million compared to $37.7 million for the year ended December 31, 2024, representing a 109.3% increase. This increase of $41.2 million is primarily related to: (i) $15.8 million higher revenues related to merchant rates at PJM storage facilities in 2025, compared to 2024. (ii) the East Flemington facility which commenced commercial operations in the first quarter of 2024, the Bottleneck and Montague energy storage facilities which commenced commercial operations in the fourth quarter of 2024 and the Lower Rio facility that commenced commercial operations in September 2025.

Total Cost of Revenues

	Year Ended December 31, 2025	Year Ended December 31, 2024	Increase (Decrease)	
	(Dollars in millions)			
Electricity segment cost of revenues	$ 496.0	$ 459.5	$ 36.5	7.9 %
Product segment cost of revenues	170.7	113.9	56.8	49.8
Energy Storage segment cost of revenues	50.2	33.6	16.6	49.4
Total Cost of Revenues	$ 716.9	$ 607.0	$ 109.9	18.1 %

Electricity Segment

Total cost of revenues attributable to our Electricity segment for the year ended December 31, 2025 was $496.0 million, compared to $459.5 million for the year ended December 31, 2024, representing a 7.9% increase. This increase of

$36.5 million is primarily attributable to: (i) an increase in power plants depreciation expenses of $20.0 million, as a result of our investments in our power plants; (ii) an increase of $8.3 million in property tax expenses primarily related to the CD4 power plant, the Heber complex, and the Steamboat power plant; (iii) an increase of $2.3 million in the Stillwater power plant as a result of maintenance work during the third quarter of 2025; (iv) an increase of $2.0 million related to the Blue Mountain power plant which was purchased in June 2025; and other smaller amount increases in several other power plants.

As a percentage of total Electricity revenues, the total cost of revenues attributable to our Electricity segment for the year ended December 31, 2025 was 71.5%, compared to 65.4% for the year ended December 31, 2024. This increase was primarily attributable to higher depreciation and property tax expenses in some of our power plants, as well as the impact of curtailments on our revenues, as described above. The cost of revenues attributable to our international power plants was 17.8% of our Electricity segment cost of revenues for the year ended December 31, 2025, compared to 18.3% for the year ended December 31, 2024.

Product Segment

Total cost of revenues attributable to our Product segment for the year ended December 31, 2025 was $170.7 million, compared to $113.9 million for the year ended December 31, 2024, representing a 49.8% increase from the prior year. This increase was primarily attributable to the higher revenues in 2025, compared to 2024, as well as the higher profitability of projects for which revenues were recognized in 2025, compared to projects for which revenues were recognized in 2024. As a percentage of total Product segment revenues, our total cost of revenues attributable to our Product segment for the year ended December 31, 2025 was 78.8%, compared to 81.6% for the year ended December 31, 2024.

Energy Storage Segment

Cost of revenues attributable to our Energy Storage segment for the year ended December 31, 2025 were $50.2 million as compared to $33.6 million in the year ended December 31, 2024. This increase of $16.6 million was mainly due to costs related to the new energy storage facilities that came online during 2024 and 2025 such as Bottleneck, Montague, East Flemington and Lower Rio as described above.

Research and Development Expenses

Research and development expenses for the year ended December 31, 2025 were $6.3 million, compared to $6.5 million for the year ended December 31, 2024, representing a 3.0% decrease.

Selling and Marketing Expenses

Selling and marketing expenses for the year ended December 31, 2025 were $18.9 million, compared to $17.7 million for the year ended December 31, 2024, representing a 6.8% increase. Selling and marketing expenses constituted 1.9% and 2.0% of total revenues for the years ended December 31, 2025 and 2024, respectively.

General and Administrative Expenses

General and administrative expenses for the year ended December 31, 2025 were $79.6 million, compared to $80.1 million for the year ended December 31, 2024, representing a 0.7% decrease or $0.5 million. The decrease was primarily attributable to legal fees related to a settlement agreement with a third-party battery systems supplier of $4.0 million, which was recorded in 2024, partially offset by other legal and consulting fees in 2025 compared to 2024, as well timing of when we incur services from our vendors.

General and administrative expenses for the year ended December 31, 2025 constituted 8.0% of total revenues for such period, compared to 9.1%, for the year ended December 31, 2024.

Other Operating Income

Other operating income for the year ended December 31, 2025 was $14.8 million compared to $9.4 million for the year ended December 31, 2024. Other operating income primarily represents the non-refundable portion of the recovery of damages received from a third-party battery systems supplier as part of a settlement agreement entered into in August 2024 for which all contingency conditions have been met, as further described under Note 1 to the consolidated financial statements. The increase in “Other operating income” year-over-year of $5.5 million, primarily relates to a full year period in 2025 during which all contingency conditions have been met, as compared to a shorter period of such in 2024.

Impairment of long-lived assets

Impairment of long-lived assets for the year ended December 31, 2025 was $12.1 million compared to $1.3 million for the year ended December 31, 2024. The impairment of long-lived assets in 2025 is primarily related to: (i) $7.2 million

associated with the Brawley power plant write-off as a result of continuous losses primarily attributable to wellfield issues which have resulted in higher-than-expected operating costs and lower-than-expected electricity revenues; and (ii) $4.9 million associated with the expected termination of a waste heat agreement between the Company's wholly-owned subsidiary, OREG2, and its customer. The impairment of long-lived assets in 2024 is related to the termination of the waste heat agreement between the Company's wholly-owned subsidiary, OREG4, and its customer.

Write-off of Unsuccessful Exploration and Storage Activities

Write-offs of unsuccessful exploration and storage activities for year ended December 31, 2025 were $1.4 million compared to $3.9 million for the year ended December 31, 2024. These write-offs are primarily related to geothermal exploration projects that the Company decided to no longer pursue, as well as costs related to a number of battery energy storage projects that the Company decided to no longer develop and pursue.

Interest Income

Interest Income for the year ended December 31, 2025 was $6.0 million, compared to $7.9 million for the year ended December 31, 2024. Interest income is primarily related to interest earned on cash and cash equivalents held by the Company during the period. The decrease in interest income is primarily related to lower balances of cash and cash equivalents during 2025 compared to 2024, as well as lower average interest rate, year-over-year.

Interest Expense, Net

Interest expense, net, for the year ended December 31, 2025 was $141.9 million, compared to $134.0 million for the year ended December 31, 2024, representing a 5.8% increase. This increase of $7.8 million is primarily attributable to the new long-term loans entered into during 2025 and 2024 of $548.5 million and $514.6 million, respectively (net of deferred financing costs), and the issuance of the additional 2.50% senior convertible notes in July 2024. This increase was partially offset by an increase in the amount of interest capitalized due to an increase in the construction-in-process balance and lower interest expenses on other long-term loans as a result of regular principal payments.

Derivatives and Foreign Currency Transaction Gains (Losses)

Derivatives and foreign currency transaction gains (losses) for the year ended December 31, 2025 was a gain of $5.2 million, compared to a loss of $4.2 million for the year ended December 31, 2024. Derivatives and foreign currency transaction gains (losses) primarily includes gains and losses from foreign currency forward contracts which were not accounted for as hedge transactions, and the impact of changes in foreign currency exchange rates against the U.S. Dollar.

Income Attributable to Sale of Tax Benefits

Income attributable to the sale of tax benefits for the year ended December 31, 2025 was $66.7 million, compared to $73.1 million for the year ended December 31, 2024. 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, and to income related to the expected sale of transferable production tax credits under the existing IRA regulations. This decrease of $6.3 million is primarily related to lower generation in certain power plants and the buyout of Opal Geo in July 2024, partially offset by an increase in PTC rates.

Other Non-Operating Income (Expense), Net

Other non-operating income, net for the year ended December 31, 2025 was an income of $0.4 million, compared to an income of $0.2 million for the year ended December 31, 2024. Other non-operating income, net is primarily related to certain immaterial non-operating proceeds from various third-parties.

Income Taxes

Income tax (provision) benefit for the year ended December 31, 2025, was a benefit of $20.3 million, an increase of $4.0 million compared to an income tax benefit of $16.3 million for the year ended December 31, 2024. Our effective tax rate for the year ended December 31, 2025 and 2024, was (19.2)% and (14.1)%, respectively. The effective rate differs from the federal statutory rate of 21% for the year ended December 31, 2025 due to the generation of investment tax credits, a net benefit associated with the U.S. state effective tax rate, an expense recorded associated with unrecognized tax benefits, and the jurisdictional mix of earnings at differing tax rates from the federal statutory tax rate.

Equity in Earnings (losses) of Investees, net

Equity in earnings (losses) of investees, net in the year ended December 31, 2025, was a net gain of $1.0 million, compared to a net loss of $0.4 million in the year ended December 31, 2024. Equity in earnings (losses) of investees, net is mainly derived from our 12.75% share in the earnings or losses in the Sarulla project, and our 49% share in the earnings or losses in the Ijen geothermal project. The increase in this line item is primarily related to an increase in net income generated by the Ijen project in 2025, compared to 2024. In the second quarter of 2022, Sarulla agreed with its banks on a framework that will enable it to perform remediation works that are aimed to restore the power plants' performance. The first phase of the recovery plan included the drilling of an additional production well, which was successful, and certain modifications to surface equipment are still underway. Following the positive indications from the first phase, during the second quarter of 2024, Sarulla commenced discussions with the banks towards implementation of the additional phases and expects to commence drilling of additional two wells, in 2026, aiming for the same target zone of the successful well drilled earlier.

Net Income attributable to the Company's Stockholders

Net income attributable to the Company's stockholders for the year ended December 31, 2025 was $123.9 million, compared to $123.7 million for the year ended December 31, 2024, which represents an increase of $0.2 million. This increase was attributable to the decrease in net income which was affected by the factors described above, as well as a decrease of $4.4 million in net income attributable to noncontrolling interest which is primarily related to the noncontrolling share in the net results of the Puna and Guadeloupe power plants.

Liquidity and Capital Resources

Overview of Sources and Uses of Cash

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 and issuances of debt securities, equity offerings, project financing and tax monetization transactions, short term borrowing under our lines of credit, proceeds from the sale of equity interests in one or more of our projects and sale of transferable PTCs. We have utilized this cash to develop and construct power plants, storage facilities, fund our acquisitions, pay down existing outstanding indebtedness, and meet our other cash and liquidity needs.

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.

As of December 31, 2025, we had access to: (i) $147.4 million in cash and cash equivalents, of which $75.4 million was held by our foreign subsidiaries; and (ii) $388.9 million of unused corporate borrowing capacity under existing committed lines for credit and letters of credit with different commercial banks.

As of December 31, 2025, $286.0 million in the aggregate was outstanding under different credit agreements with several banks as detailed below under "Letters of Credits under the Credit Agreements".

Our estimated capital needs for 2026 include approximately $675.0 million for capital expenditures on new projects under development or construction including storage projects, exploration activity, investment in EGS pilot and maintenance capital expenditures for our existing projects. In addition, we expect $303.7 million for long-term debt repayments.

Our capital expenditures primarily relate to the enhancement of our existing power plants and the construction of new power plants. We have budgeted approximately $808.0 million in capital expenditures for construction of new projects and enhancements to our existing power plants, of which we had invested $208.0 million as of December 31, 2025. We expect to invest approximately $240.0 million in 2026 and the remaining approximately $360.0 million on thereafter.

In addition, we estimate approximately $435.0 million in additional capital expenditures in 2026 to be allocated as follows: (i) approximately $170.0 million for the exploration, drilling and development of new projects and enhancements of existing power plants that are not yet released for full construction; (ii) approximately $10 million for EGS pilot (iii) approximately $55.0 million for maintenance of capital expenditures to our Electricity segment operating power plants; (iv) approximately $180.0 million for the construction and development of storage projects; (v) approximately $10 million for land acquisition and other business development initiatives and (vi) approximately $10.0 million for enhancements to our production facilities.

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.

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.

The table below describes our committed and non-committed lines:

Credit Agreements	Amount Issued	Issued and Outstanding as of December 31, 2025	Termination Date
		(Dollars in millions)	
Committed lines for credit and letters of credit	$ 533.0	$ 144.1	March 2026 - June 2028
Committed lines for letters of credit	155.0	109.6	March 2026 - August 2027
Non-committed lines	-	32.3	June 2026 - October 2026
Total	**$ 688.0**	**$ 286.0**	

Credit Agreements

Credit Agreement with MUFG Union Bank

Ormat Nevada has a credit agreement with MUFG Union Bank under which it has an aggregate available credit of up to $100.0 million as of December 31, 2025. The credit termination date is June 30, 2026.

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. As of December 31, 2025, letters of credit in the aggregate amount of $80.0 million were issued and outstanding under this credit agreement.

Credit Agreement with HSBC Bank USA N.A.

Ormat Nevada has 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, 2026. On December 31, 2025, the aggregate amount available under the credit agreement was $35.0 million. This credit line is limited to the issuance, extension, modification or amendment of letters of credit. In addition, Ormat Nevada has an uncommitted discretionary demand line of credit in the aggregate amount of $65.0 million available for letters of credit including up to $40 million of credit. 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. As of December 31, 2025, letters of credit in the aggregate amount of $33.7 million were issued and outstanding under the committed portion of this credit agreement and $21.6 million under the uncommitted portion of the agreement.

Restrictive Covenants

Our obligations under the credit agreements, the loan agreements, and the trust instrument, 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, including the credit agreements with MUFG Union Bank and with HSBC Bank USA N.A., we have agreed to maintain certain financial ratios, which are measured quarterly, such as: (i) equity of at least $750 million and in no event less than 25% of total assets; and (ii) 12-month debt, net of cash, cash equivalents, and short-term bank deposits to Adjusted EBITDA ratio not to exceed 6. As of December 31, 2025: (i) total equity was $2,680.9 million and the actual equity to total assets ratio was 42.9%; and (ii) the 12-month debt, net of cash and cash equivalents to Adjusted EBITDA ratio was 4.36. During the year ended December 31, 2025, we distributed interim dividends in an aggregate amount of $29.1 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, except as described below, 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.

As of December 31, 2025, we did not meet the dividend distribution criteria related to the DAC 1 Senior Secured Notes, which resulted in certain equity distribution restrictions from this related subsidiary. As of December 31, 2025, the amount restricted for distribution by this subsidiary was $1.0 million. There were no restrictions on the retained earnings or net income of Ormat Technologies, Inc., as the parent company, in respect of these matters, as of December 31, 2025.

Future minimum payments

Material future minimum payments under long-term obligations as of December 31, 2025, are detailed under the caption Contractual Obligations and Commercial Commitments, below and under Note 11 to the consolidated financial statements.

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; (ii) full-recourse debt incurred by us or our subsidiaries for general corporate purposes; (iii) convertible senior notes; (iv) commercial paper; (iv) financing liability; and (v) short term revolving credit lines with banks. Further details related to our third-party debt are provided under Note 11 to the consolidated financial statements.

Non-recourse debt refers to debt involving debt repayments 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.

Non-Recourse and Limited-Recourse Third-Party Debt:

Loan	Amount Issued	Balance as of December 31, 2025	Annual Interest rate	Maturity Date	Related Project	Location
	(Dollars in millions)					
Mammoth Senior Secured Notes 2025	$ 23.4	$ 23.4	6.95 %	July, 2034	Mammoth Complex	United States
Geothermie Bouillante tranche 1	39.2	35.7	(3)	December, 2030	Geothermie Bouillante	Guadeloupe
Geothermie Bouillante tranche 2	55.7	56.3	(4)	June, 2046	Geothermie Bouillante	Guadeloupe
Dominica Loan	37.6	37.6	2.40	September, 2042	Dominica	Dominica
Bottleneck Loan	72.6	68.9	6.31	November, 2039	Bottleneck	United States
Mammoth Senior Secured Notes	135.1	120.4	6.73	July, 2047	Mammoth Complex	United States
OFC 2 Senior Secured Notes – Series A	151.7	48.6	4.69	December, 2032	McGinness Hills phase 1, Tuscarora	United States
OFC 2 Senior Secured Notes – Series C	140.0	62.6	4.61	December, 2032	McGinness Hills phase 2	United States
Olkaria III Financing Agreement with DFC – Tranche 1	85.0	23.6	6.34	December, 2030	Olkaria III Complex	Kenya
Olkaria III Financing Agreement with DFC – Tranche 2	180.0	47.6	6.29	June, 2030	Olkaria III Complex	Kenya
Olkaria III Financing Agreement with DFC – Tranche 3	45.0	13.4	6.12	December, 2030	Olkaria III Complex	Kenya
Don A. Campbell Senior Secured Notes	92.5	46.9	4.03	September, 2033	Don A. Campbell Complex	United States
Idaho Refinancing Note (1)	61.6	52.4	6.26	March, 2038	Neal Hot Springs, Raft River	United States
U.S. Department of Energy loan (2)	96.8	24.8	2.60	February, 2035	Neal Hot Springs	United States
Prudential Capital Group Nevada Loan	30.7	21.7	6.75	December, 2037	San Emidio	United States
Platanares Loan with DFC	114.7	55.3	7.02	September, 2032	Platanares	Honduras
Total	**$ 1,361.6**	**$ 739.2**				

(1) Secured by equity interest.

(2) Secured by the assets.

(3) 3-month EUROBOR+1.8%

(4) 3-month EUROBOR+2.0%

Full-Recourse Third-Party Debt:

Loan	Amount Issued	Balance as of December 31, 2025	Annual Interest rate	Maturity Date
	(Dollars in millions)			
Discount 2025 III Loan	$ 100.0	$ 100.0	3-month SOFR+2.42%	November 2034
Discount 2025 II Loan	50.0	46.9	3-month SOFR+2.4%	May 2033

Hapoalim 2025 Loan	150.0	137.6	3-month SOFR+2.45%	March 2033
Discount 2025 Loan	50.0	45.3	3-month SOFR+2.4%	February 2033
Mizrahi 2025 Loan	50.0	46.9	6-month SOFR+2.35%	April 2033
Hapoalim 2024 Loan	75.0	58.6	6.60%	January 2032
HSBC Bank 2024 Loan	125.0	87.5	3-month SOFR+2.25%	January 2028
Mizrahi Loan	75.0	42.2	4.10	April 2030
Mizrahi Loan 2023	50.0	37.5	7.15	October 2031
Hapoalim Loan	125.0	44.6	3.45	June 2028
Hapoalim 2023 Loan	100.0	75.0	6.45	February 2033
HSBC Loan	50.0	21.4	3.45	July 2028
Discount Loan	100.0	50.0	2.90	September 2029
Discount 2024 Loan	31.8	25.8	6.75	May 2032
Discount 2024 II Loan [1]	50.0	42.2	3-month SOFR+2.35%	September 2028
Senior Unsecured Bonds Series 4 [2]	289.8	188.1	3.35	June 2031
Senior Unsecured Loan 1	100.0	62.3	4.80	March 2029
Senior Unsecured Loan 2	50.0	31.1	4.60	March 2029
Senior Unsecured Loan 3	50.0	31.1	5.44	March 2029
DEG Loan 2	50.0	12.5	6.28	June 2028
DEG Loan 3	41.5	10.9	6.04	June 2028
DEG Loan 4	30.0	30.0	7.79	June 2031
Total	**$ 1,793.1**	**$ 1,227.5**		

[1] The Discount 2024 II Loan bears an annual interest of 3-month Term SOFR plus 2.35%, but not less than Term SOFR of 2.5%.

[2] Bonds issued in total aggregate principal amount of NIS 1.0 billion.

Other Third-Party Debt

Loan	Balance as of December 31, 2025	Annual Interest Rate	Maturity Date
	(Dollar in millions)		
Financing Liability - Dixie Valley [1]	$ 216.4	6.01%	June 2038
Convertible Senior Notes [2]	476.4	2.50	July 2027
Commercial Paper [3]	100.0	* [3]	* [3]

[1] Final maturity date of the financing liability is assuming execution of the buy-out option in June 2038.

[2] The Notes mature in July 2027, unless earlier converted, redeemed or repurchased.

[3] The Commercial Paper was issued on October 23, 2023 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 Commercial Paper Agreement. The Commercial Paper bears an annual interest of three months SOFR +1.1% which will be paid at the end of each 90-day period. As of December 31, 2025, the base rate was 5.0%.

For additional description of our long-term debt, see Note 11 to our consolidated financial statements, set forth in Item 8 of this Annual Report.

Liquidity Impact of Uncertain Tax Positions

As discussed in Note 16 - 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 $10.4 million as of December 31, 2025. 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

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.

The following are the dividends declared by us during the past two years, as of December 31, 2025 :

Date Declared	Dividend Amount per Share	Record Date	Payment Date
February 21, 2024	$ 0.12	March 6, 2024	March 20, 2024
May 8, 2024	$ 0.12	May 22, 2024	June 5, 2024
August 6, 2024	$ 0.12	August 20, 2024	September 3, 2024
November 6, 2024	$ 0.12	November 20, 2024	December 4, 2024
February 26, 2025	$ 0.12	March 12, 2025	March 26, 2025
May 7, 2025	$ 0.12	May 21, 2025	June 4, 2025
August 6, 2025	$ 0.12	August 20, 2025	September 3, 2025
November 3, 2025	$ 0.12	November 17, 2025	December 1, 2025
February 24, 2026	$ 0.12	March 10, 2026	March 24, 2026

Historical Cash Flows

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

	Year Ended December 31,		
	2025	2024	2023
	(Dollars in thousands)		
Net cash provided by operating activities	$ 335,101	$ 410,919	$ 309,401
Net cash used in investing activities	(726,435)	(780,254)	(628,343)
Net cash provided by financing activities	465,746	287,916	379,964
Translation adjustments on cash and cash equivalents	682	(579)	72
Net change in cash and cash equivalents and restricted cash and cash equivalents	$ 75,094	$ (81,998)	$ 61,094

For the Year Ended December 31, 2025

Net cash provided by operating activities for the year ended December 31, 2025 was $335.1 million, compared to $410.9 million for the year ended December 31, 2024, representing a net decrease of $75.8 million. Net cash provided by operating activities for the year ended December 31, 2025, was primarily attributable to net income of $127.0 million adjusted for certain non-cash items such as depreciation and amortization, stock-based compensation, income attributable to sale of tax benefits, impairment charges, and deferred income tax provision, among others, as well as primarily by: (i) net increase of $60.5 million in costs and estimated earnings in excess of billings on uncompleted contracts and billings in excess of costs and estimated earnings on uncompleted contracts, as a result of timing of billing to our customers; (ii) a net increase of $7.2 million in inventory primarily related to the progress of our Product projects and timing of allocating costs to such projects; and (iii) a net decrease in accounts payable and accrued expenses of $1.8 million as a result of timing of payments to our suppliers. This decrease was partially offset by (i) cash inflow related to the net decrease in trade receivables of $4.5 million, due to the timing of collection from our customers; and (ii) a net decrease in deposits and other of $5.8 million, primarily related to certain refunds. Net cash provided by operating activities for the year ended December 31, 2024 was $410.9 million, compared to $309.4 million for the year ended December 31, 2023, representing a net increase of $101.5 million. Net cash provided by operating activities for the year ended December 31, 2024, was primarily attributable to net income of $131.2 million adjusted for certain non-cash items such as depreciation and amortization,

stock-based compensation, and income attributable to sale of tax benefits, among others, as well as primarily by: (i) cash inflow related to the net decrease in trade receivables of $27.2 million, due to the timing of collection from our customers; (ii) a net increase in accounts payable and accrued expenses of $11.4 million as a result of timing of payments to our suppliers, and a payment related to recovery of damages received from a third-party battery systems supplier as part of a settlement agreement; (iii) a net increase in prepaid expenses and other of $8.5 million, primarily as a result of timing of prepayments to our suppliers and governmental authorities; and (iv) a net decrease of $6.9 million in inventory, primarily related to the progress of our Product projects and timing of allocating costs to such projects. This increase was partially offset a net increase of $32.3 million in costs and estimated earnings in excess of billings on uncompleted contracts and billings in excess of costs and estimated earnings on uncompleted contracts, as a result of timing of billing to our customers, and a net increase in deposit and others of $4.5 million related to timing of payment deposits required for ongoing operations.

Net cash used in investing activities for the year ended December 31, 2025 was $726.4 million, compared to $780.3 million for the year ended December 31, 2024. The principal factors that affected the decrease of $53.8 million in our net cash used in investing activities during the year ended December 31, 2025 were cash consideration of $88.7 million paid for the acquisition of the Blue Mountain power plant in 2025, compared to cash consideration of $274.6 million paid for the purchase transaction with Enel EGPNA in 2024, partially offset by capital expenditures of $619.8 million in 2025 compared to $487.7 million in 2024, primarily for our geothermal power plants and storage facilities under construction that support our growth plan.

Net cash provided by financing activities for the year ended December 31, 2025 was $465.7 million, compared to $287.9 million for the year ended December 31, 2024. The principal factors that affected the increase in net cash provided by financing activities during the year ended December 31, 2025 were: (i) net proceeds of $548.5 million from long-term loans entered into during 2025; (ii) net proceeds related to tax monetization transactions of $152.0 million; (iii) net proceeds from revolving credit lines with banks of $80.0 million; and cash received from noncontrolling interest of $10.3 million. These cash inflows were partially offset by: (i) scheduled repayments of long-term debt in the amount of $265.5 million; (ii) cash dividend payments of $29.1 million; and (iii) cash paid in respect of debt and tax monetization transactions issuance costs of $20.8 million. The principal factors that affected net cash provided by financing activities during the year ended December 31, 2024 were: (i) net proceeds of $514.6 million from long-term loans entered into during the period such as the Hapoalim 2024 Loan, the HSBC 2024 Loan, the Mammoth Senior Secured Notes, the DEG 4 Loan, the Discount 2024 Loan, the Discount 2024 II Loan, and the Bottleneck Loan; (ii) net proceeds of $44.0 million related to proceeds from issuance of the Additional Notes; and (iii) cash received from noncontrolling interest in the amount of $12.3 million. These cash inflows were partially offset by: (i) scheduled repayments of long-term debt in the amount of $209.3 million; (ii) cash dividend payments of $29.1 million; (iii) cash paid pursuant to a transaction with noncontrolling interest of $9.8 million; and (iv) net repayments of revolving credit lines with banks of $20.0 million.

For the Year Ended December 31, 2024

A discussion of changes in our cash flows in 2024 compared to 2023 has been omitted from this Form10-K, but may be found in “Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations” of our Form 10-K for the fiscal year ended December 31, 2024, filed with the SEC on February 27, 2025, which is incorporated by reference herein. This Form 10-K is available free of charge on the SECs website at www.sec.gov and at www.Ormat.com, by clicking “Investors” located at the top of the home page.

Total EBITDA and Adjusted EBITDA

We calculate EBITDA as net income before interest, taxes, depreciation, amortization and accretion. We calculate Adjusted EBITDA as net income before interest, taxes, depreciation, amortization and accretion, adjusted for (i) mark-to-market gains or losses from accounting for derivatives not designated as hedging instruments; (ii) stock-based compensation; (iii) merger and acquisition transaction costs; (iv) gain or loss from extinguishment of liabilities; (v) costs related to settlement agreements; (vi) non-cash impairment charges; (vii) write-off of unsuccessful exploration and storage activities; (viii) allowance for bad debts; and (ix) other unusual or non-recurring items. We adjust for these factors as they may be non-cash, unusual in nature and/or are not factors used by management for evaluating operating performance. We believe that presentation of these measures will enhance an investor’s ability to evaluate our financial and operating performance. EBITDA and Adjusted EBITDA are not measurements of financial performance or liquidity under accounting principles generally accepted in the U.S., 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. Our Board of Directors and senior management use EBITDA and Adjusted EBITDA to evaluate 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.

Net income for the year ended December 31, 2025 was $127.0 million, compared to $131.2 million for the year ended December 31, 2024 and $133.1 million for the year ended December 31, 2023.

Adjusted EBITDA for the year ended December 31, 2025 was $582.0 million, compared to $550.5 million for the year ended December 31, 2024 and $481.7 million for the year ended December 31, 2023.

The following table reconciles net income to EBITDA and Adjusted EBITDA for the years ended December 31, 2025, 2024 and 2023:

	Year Ended December 31,		
	2025	2024	2023
	(Dollars in thousands)		
Net income	$ 126,990	$ 131,241	$ 133,137
Adjusted for:			
Interest expense, net (including amortization of deferred financing costs)	135,836	126,148	86,898
Income tax provision (benefit)	(20,282)	(16,289)	5,983
Adjustment to investment in unconsolidated companies: our proportionate share in interest expense, tax and depreciation and amortization in Sarulla and Ijen	15,086	17,637	16,069
Depreciation, amortization and accretion	287,505	259,151	221,415
EBITDA	$ 545,135	$ 517,888	$ 463,502
Mark-to-market of derivative instruments	550	856	(2,206)
Stock-based compensation	19,390	20,197	15,478
Allowance for bad debts	228	355	—
Impairment of long-lived assets	12,064	1,280	—
Write-off of unsuccessful exploration and storage activities	1,446	3,930	3,733
Merger and acquisition transaction costs	2,272	1,949	1,234
Settlement agreements	900	4,000	—
Adjusted EBITDA	$ 581,985	$ 550,455	$ 481,741

Adjusted EBITDA for the fiscal year 2025 increased by 5.7% compared to fiscal year 2024, primarily due to an increase in EBITDA of $27.2 million, or 5.3%, as illustrated above. EBITDA and Adjusted EBITDA include our proportionate share (12.75% and 49%) of Sarulla's and Ijen EBITDA and Adjusted EBITDA, respectively. As of December 31, 2025, the outstanding carrying value of long-term debt owed by Sarulla and Ijen, our unconsolidated investments, was $645.3 million, and $105.0 million, respectively, in which our proportionate share was $82.3 million, and $51.5 million, respectively.

Exposure to Market Risks

We, like other power plant operators, are exposed to electricity price volatility risk. Our exposure to such market risk is currently limited because the majority of our long-term PPAs have fixed or escalating rate provisions that limit our exposure to changes in electricity prices, except for 25 MW PPA for the Puna complex. Our energy storage projects sell primarily on a "merchant" basis and are exposed to changes in the electricity market prices. The prices paid for electricity pursuant to the 25MW PPA for the Puna Complex in Hawaii change primarily as a result of variations in the price of oil as well as other commodities. Accordingly, our revenues from this power plant may fluctuate. In 2024, the HPUC approved a new PPA related to Puna with fixed prices, increased capacity and an extension of the term until 2052, which we expect to be in effect in early 2027.

As of December 31, 2025, 84.3% of our consolidated long-term debt was at fixed interest rates and therefore was not subject to interest rate volatility risk. Our variable interest rate long-term debt, as of the aforementioned date, is predominantly associated with either the 3-month SOFR or EUROBOR rate, as further detailed under Note 11 to the consolidated financial statements. Additionally, our short-term commercial paper, which was issued on October 23, 2023, bears an annual interest of 3-months SOFR+1.1%, and therefore present an exposure to interest rate volatility. The outstanding amount of the short-term commercial paper as of December 31, 2025 was $100.0 million.

Our cash equivalents are subject to interest rate risk. We currently maintain our surplus cash in short-term, interest-bearing bank deposits, money market funds, corporate bonds and debt securities available for sale (with a minimum investment grade rating of A+ by Standard & Poor's Ratings Services).

We are also exposed to foreign currency exchange risk, in particular the fluctuation of the U.S. dollar versus the New Israeli Shekels ("NIS") in Israel, the Euro in Guadeloupe, and the New-Zealand Dollar in respect with our operation there. 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 related asset and liability are recorded in Kenyan Shillings ("KES"), therefore, any change in the exchange rate in the KES versus the U.S. dollar has an impact on our financial results. Risks attributable to fluctuations in the 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 Bouillante 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 and cross-currency swap contracts in place to reduce our NIS/U.S. dollar currency exposure related to our Senior Unsecured Bonds - Series 4, as detailed below, 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.

On July 1, 2020, we concluded an auction tender and accepted subscriptions for senior unsecured bonds comprised of NIS 1.0 billion aggregate principal amount (the "Senior Unsecured Bonds - Series 4"). The Senior Unsecured Bonds - Series 4 were issued in New Israeli Shekels and converted to approximately $290 million using a cross-currency swap transaction shortly after the completion of such issuance. In June 2022, we issued $431.3 million aggregate principal amount of our 2.5% convertible senior notes due in 2027. The Notes bear annual interest of 2.5%, payable semiannually in arrears, and mature on July 15, 2027, unless earlier converted, redeemed or repurchased. In July 2024, we issued an additional $45.2 million aggregate principal amount of our 2.50% convertible senior notes due 2027 under the same terms.

We performed a sensitivity analysis on the fair values of our long-term debt obligations, commercial paper, 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, 2025 and 2024 by a hypothetical 10% and calculating the resulting change in the fair values.

Currently, the development of our 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, 2025 and 2024 are presented below:

	Assuming a 10% Increase in Rates		Assuming a 10% Decrease in Rates		
	As of December 31,		As of December 31,		
Risk	2025	2024	2025	2024	Change in the Fair Value of
	(In thousands)				
Foreign Currency	$ —	$ (700)	$ —	$ 2,078	Foreign Currency Forward Contracts
Interest Rate	(582)	—	605	—	Mammoth Senior Secured Notes 2025
Interest Rate	(1,397)	—	1,477	—	Dominica Loan
Interest Rate	(2,453)	—	2,562	—	Geothermie Bouillante Loan
Interest Rate	(895)	—	921	—	Mizrahi 2025 Loan
Interest Rate	(869)	—	893	—	Discount 2025 Loan

	Assuming a 10% Increase in Rates		Assuming a 10% Decrease in Rates		
	As of December 31,		As of December 31,		
Risk	2025	2024	2025	2024	Change in the Fair Value of
Interest Rate	(930)	—	958	—	Discount 2025 II Loan
Interest Rate	(2,323)	—	2,406	—	Discount 2025 III Loan
Interest Rate	(2,547)	—	2,620	—	Hapoalim 2025 Loan
Interest Rate	(2,683)	(2,986)	2,839	3,180	Bottleneck Loan
Interest Rate	(4,580)	(5,096)	4,904	5,469	Mammoth Senior Secured Notes
Interest Rate	(317)	(574)	321	584	Mizrahi Loan
Interest Rate	(592)	(886)	606	914	Mizrahi Loan 2023
Interest Rate	(338)	(679)	342	691	Hapoalim Loan
Interest Rate	(1,343)	(1,708)	1,381	1,762	Hapoalim 2023 Loan
Interest Rate	(906)	(1,295)	927	1,333	Hapoalim 2024 Loan
Interest Rate	(147)	(289)	149	294	HSBC Loan
Interest Rate	(611)	(1,213)	617	1,233	HSBC Bank 2024 Loan
Interest Rate	(448)	(759)	455	776	Discount Loan
Interest Rate	(438)	(599)	449	617	Discount 2024 Loan
Interest Rate	(472)	(851)	479	871	Discount 2024 II Loan
Interest Rate	(8,347)	(9,275)	8,853	9,882	Financing Liability
Interest Rate	(2,042)	(2,617)	2,101	2,704	OFC 2 LLC Senior Secured Notes
Interest Rate	(1,259)	(1,909)	1,288	1,965	Olkaria III Loan - DFC
Interest Rate	(723)	(924)	744	960	DEG 4 Loan
Interest Rate	(2,863)	(3,542)	2,939	3,661	Senior Unsecured Bonds
Interest Rate	(123)	(240)	125	245	Olkaria III plant 4 - DEG 2
Interest Rate	(100)	(197)	102	201	DEG 3 Loan
Interest Rate	(962)	(1,142)	999	1,189	DAC 1 Senior Secured Notes
Interest Rate	(1,669)	(2,491)	1,704	2,561	Senior Unsecured Loan (Migdal)
Interest Rate	(749)	(835)	793	886	Prudential - NV
Interest Rate	(471)	(583)	485	603	DOE Loan
Interest Rate	(1,806)	(2,026)	1,922	2,164	Prudential - Idaho Refinancing
Interest Rate	(1,160)	(1,517)	1,198	1,574	Platanares Loan - DFC Loan
Interest Rate	(17)	(22)	17	22	Commercial paper
Interest Rate	—	(17)	—	17	Other long-term loans

Effect of Inflation

Over the last five years, although to a lesser extent during 2024 and 2025, we experienced an increase in the overall operating and other costs as a result of higher inflation rates, in particular in the U.S. To address the possibility of 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 Consumer Price Index ("CPI"), although some of them have a fixed annual indexation. Inflation may directly impact the expenses 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. In addition to the Puna rates that are impacted by higher commodity prices, 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 third-party power plants, thereby lowering our profit margins at the Product segment. We are more likely to be able to offset long term, 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.

Interest rate for both short-term and long-term debt have increased sharply until 2024 and 2025 during which rates started to come down. Although our outstanding debt bears fixed interest rates, as we refinance it, or borrow additional amounts, we may incur additional interest expense versus expiring loans.

In recent months, we see a slowdown in inflation rates and increases in raw materials costs that we believe have returned to normal levels.

Contractual Obligations and Commercial Commitments

The following tables set forth our material contractual obligations as of December 31, 2025 :

	Payments Due by Period						
	Total	2026	2027	2028	2029	2030	Thereafter
	(Dollars in thousands)						
Long-term debt and financing liability - principal	$2,660,570	$ 303,653	$ 780,897	$ 335,092	$ 313,212	$ 211,681	$ 716,034
Interest on long-term debt and financing liability [1]	613,672	129,379	107,646	83,764	65,038	50,203	177,643
	$3,274,242	$ 433,032	$ 888,543	$ 418,856	$ 378,250	$ 261,884	$ 893,677

[1] Interest rates and maturity dates are detailed under the Liquidity and Capital Resources section above.

The above table does not reflect a liability associated with the sale of tax benefits of $190.2 million. Refer to Note 12 to our consolidated financial statements as set forth in Item 8 of this Annual Report for additional discussion of our liability associated with the sale of tax benefits.

Concentration of Credit Risk

Our credit risk is currently concentrated with the following major customers: Sierra Pacific Power Company and Nevada Power Company (subsidiaries of NV Energy), SCPPA, and KPLC. If any of these electric utilities fail to make payments under their respective 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.

The Company's revenues from its primary customers as a percentage of total revenues are as follows:

	Year Ended December 31,		
	2025	2024	2023
Southern California Public Power Authority (“SCPPA”)	17.8 %	20.6 %	21.2 %
Sierra Pacific Power Company and Nevada Power Company	13.8	15.1	14.1
Kenya Power and Lighting Co. Ltd. ("KPLC")	11.9	13.0	13.2

We have historically been able to collect on substantially all of our receivable balances. As of December 31, 2025, the amount overdue from KPLC in Kenya was $29.5 million of which $21.1 million was paid in January and February of 2026. The Company believes it will be able to collect all past due amounts in Kenya. This belief is supported by the fact that in addition to KPLC's obligations under its power purchase agreement, the Company holds a support letter from the Government of Kenya that covers certain cases of KPLC non-payment (such as non-payments that are caused by government actions and/or political events).

In Honduras, as of December 31, 2025, the total amount overdue from ENEE was $20.3 million of which $1.0 million was collected in January and February of 2026. In addition, due to the financial situation in Honduras, the Company may

experience additional delays in collection. The Company believes it will be able to collect all past due amounts in Honduras.

Government Grants and Tax Benefits

On July 4, 2025, the OBBBA was enacted into law in the United States. The OBBBA includes significant provisions, such as the permanent extension of certain expiring provisions of the Tax Cuts and Jobs Act of 2017 and numerous changes to the energy tax credits initially introduced and expanded under the IRA. The OBBBA allows for geothermal and battery storage to qualify for 100% PTC or ITC related to projects that start construction by the end of December 2033, 75% PTC or ITC by the end of December 2034 and 50% PTC or ITC by the end of December 2035. In order to qualify for 100% energy credit, solar projects must start construction by July 4, 2026 and be placed-in-service within four years, or start construction after July 3, 2026 and be placed-in-service by December 31, 2027. The law seeks to limit content from foreign entities of concern ("FEOC") used in energy related projects that start construction after December 31, 2025. The FEOC restrictions apply at both the product and taxpayer levels, which primarily affects products and ownership related to China.

We are currently permitted to depreciate most of the cost of a new geothermal power plant. In cases where we claim ITCs, 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 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 are currently permitted to 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 the current provision under the OBBBA and determine if an election is appropriate as it relates to our business needs. Future presidential administrations may take action to revise, repeal, or otherwise modify existing rules and regulations, including various tax incentives, and the potential impact on the Company remains uncertain at this time. For more information, see Part I of this Annual Report, Item 1A "Risk Factors—Risks Related to Governmental Regulations, Laws and Taxation —The reduction, elimination or inability to monetize government incentives could adversely affect our business, financial condition, future results and cash flows."

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. In January 2021, Ormat Systems received an approval from the Israeli Innovation Authority that it owns an "Innovation Promoting Enterprise" and therefore is eligible for a reduced corporate tax rate of 12% on its "Preferred Technological Income" for the tax years 2019 and 2020 (effective tax rate of approximately 13% for 2019 and 2020). The tax benefit of lower effective tax rate is reflected in the 2021 net income.

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

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

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

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

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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, 2025 and 2024, and the related consolidated statements of operations and comprehensive income (loss), of equity and of cash flows for each of the three years in the period ended December 31, 2025 , 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, 2025, 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, 2025 and 2024, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2025 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2025, based on criteria established in Internal Control - Integrated Framework (2013) issued by the COSO.

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 on Internal Control over Financial Reporting appearing under Item 9A. 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 Matter

The critical audit matter communicated below is a matter arising from the current period audit of the consolidated financial statements that was communicated or required to be communicated to the audit committee and that (i) relates 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 matter below, providing a separate opinion on the critical audit matter or on the accounts or disclosures to which it relates.

Estimates of Future Costs in Product Revenue Recognition

As described in Note 17 to the consolidated financial statements, $216.7 million of the Company's total revenues for the year ended December 31, 2025 was generated from product revenues, the majority of which related to long-term contracts. For the Company’s long-term contracts, control transfers over time and revenue is recognized based on the extent of progress in each period towards completion of the performance obligation. The selection of the measure of progress towards completion requires management judgment and is based on the nature of the products or services to be provided. As disclosed by management, the Company generally uses the percentage of completion method to measure progress for its contracts because management believes that measure best depicts the transfer of control to the customer, which occurs as the Company incurs costs related to those contracts. Under the percentage of completion method, the extent of progress towards completion is based on the ratio of costs incurred to date compared to the total estimated costs at completion of the performance obligation, which includes both the actual costs already incurred and the estimated costs to complete. Revenues are recognized proportionately as costs are incurred. Due to the nature of the work required to be performed on the performance obligation, management’s estimation of future costs to completion is complex and requires significant judgment. Management has disclosed that there are factors that can affect the accuracy of cost estimates, including, but not limited to, the ability to properly execute the engineering and design phases consistent with customer expectations, the availability and costs of labor and materials resources, and productivity.

The principal consideration for our determination that performing procedures relating to future costs to completion estimates in revenue recognition is a critical audit matter are 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, including the assessment of management’s judgment about the Company’s ability to properly execute the engineering and design phases consistent with customer expectations and significant assumptions related to estimated expected labor costs.

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 used 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 its projects; (ii) evaluating the timely identification of circumstances that warranted 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.

Tel-Aviv, Israel
February 26, 2026

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

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

ORMAT TECHNOLOGIES, INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

	December 31,	
	2025	2024
	(Dollars in thousands)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 147,448	$ 94,395
Restricted cash and cash equivalents (primarily related to VIEs)	133,418	111,377
Receivables:		
Trade less allowance for credit losses of $308 and $224, respectively (primarily related to VIEs)	164,772	164,050
Other	36,711	50,792
Inventories	45,268	38,092
Costs and estimated earnings in excess of billings on uncompleted contracts	30,011	29,243
Prepaid expenses and other	40,141	59,173
Total current assets	597,769	547,122
Investment in unconsolidated companies	162,111	144,585
Deposits and other (primarily related to VIEs)	137,744	75,383
Deferred income taxes	138,903	153,936
Property, plant and equipment, net ($3,460,079 and $3,271,248 related to VIEs, respectively)	3,672,569	3,501,886
Construction-in-process ($392,644 and $251,442 related to VIEs, respectively)	1,048,174	755,589
Operating leases right of use ($17,236 and $13,989 related to VIEs, respectively)	41,756	32,114
Finance leases right of use (none related to VIEs)	4,690	2,841
Intangible assets, net	274,548	301,745
Goodwill	168,244	151,023
Total assets	$ 6,246,508	$ 5,666,224
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable and accrued expenses	$ 234,757	$ 234,334
Short term revolving credit lines with banks (full recourse)	80,000	—
Commercial paper (less deferred financing costs of $17 and $23, respectively)	99,983	99,977
Billings in excess of costs and estimated earnings on uncompleted contracts	13,159	23,091
Current portion of long-term debt:		
Limited and non-recourse (primarily related to VIEs):	79,885	70,262
Full recourse	214,207	161,313
Financing liability	9,749	4,093
Operating lease liabilities	4,764	3,633
Finance lease liabilities	1,884	1,375
Total current liabilities	738,388	598,078
Long-term debt, net of current portion:		
Limited and non-recourse (primarily related to VIEs and less deferred financing costs of $13,488 and $8,849, respectively)	645,803	578,204
Full recourse (less deferred financing costs of $4,248 and $4,671, respectively)	1,009,090	822,828
Convertible senior notes (less deferred financing costs of $4,103 and $6,820, respectively)	472,334	469,617
Financing liability	206,647	216,476
Operating lease liabilities	29,760	22,523
Finance lease liabilities	2,850	1,529
Liability associated with sale of tax benefits	190,168	152,292

Deferred income taxes	68,661	68,616
Liability for unrecognized tax benefits	10,378	6,272
Liabilities for severance pay	11,942	10,488
Asset retirement obligation	135,574	129,651
Other long-term liabilities	33,637	29,270
Total liabilities	$ 3,555,232	$ 3,105,844
Commitments and contingencies (Note 20)		
Redeemable noncontrolling interest	10,402	9,448
Equity:		
The Company's stockholders' equity:		
Common stock, par value $0.001 per share; 200,000,000 shares authorized; 60,845,411 and 60,500,580 issued and outstanding as of December 31, 2025 and December 31, 2024, respectively	61	61
Additional paid-in capital	1,654,635	1,635,245
Treasury stock, at cost (258,667 shares held as of December 31, 2025 and 2024, respectively)	(17,964)	(17,964)
Retained earnings	909,343	814,518
Accumulated other comprehensive loss	(2,132)	(6,731)
Total stockholders' equity attributable to Company's stockholders	2,543,943	2,425,129
Noncontrolling interest	136,931	125,803
Total equity	2,680,874	2,550,932
Total liabilities, redeemable noncontrolling interest and equity	$ 6,246,508	$ 5,666,224

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,		
	2025	2024	2023
	(Dollars in thousands, except earnings per share data)		
Revenues:			
Electricity	$ 693,900	$ 702,264	$ 666,767
Product	216,686	139,661	133,763
Energy storage	78,957	37,729	28,894
Total revenues	989,543	879,654	829,424
Cost of revenues:			
Electricity	495,989	459,526	422,549
Product	170,671	113,911	115,802
Energy storage	50,198	33,598	27,055
Total cost of revenues	716,858	607,035	565,406
Gross profit	272,685	272,619	264,018
Operating expenses:			
Research and development expenses	6,304	6,501	7,215
Selling and marketing expenses	18,898	17,694	18,306
General and administrative expenses	79,592	80,119	68,179
Other operating income	(14,844)	(9,375)	—
Impairment of long-lived assets	12,064	1,280	—
Write-off of unsuccessful exploration and storage activities	1,446	3,930	3,733
Operating income	169,225	172,470	166,585
Other income (expense):			
Interest income	6,015	7,883	11,983
Interest expense, net	(141,851)	(134,031)	(98,881)
Derivatives and foreign currency transaction gains (losses)	5,248	(4,187)	(3,278)
Income attributable to sale of tax benefits	66,726	73,054	61,157
Other non-operating income, net	385	188	1,519
Income from operations before income tax and equity in earnings (losses) of investees	105,748	115,377	139,085
Income tax (provision) benefit	20,282	16,289	(5,983)
Equity in earnings (losses) of investees	960	(425)	35
Net income	126,990	131,241	133,137
Net income attributable to noncontrolling interest	(3,092)	(7,508)	(8,738)
Net income attributable to the Company's stockholders	123,898	$ 123,733	$ 124,399
Comprehensive income:			
Net income	126,990	131,241	133,137
Other comprehensive income (loss), net of related taxes:			
Change in foreign currency translation adjustments	9,665	(8,232)	1,257
Change in unrealized gains or (losses) in respect of the Company's share in derivatives instruments of unconsolidated investment that qualifies as a cash flow hedge	(1,230)	602	(470)
Change in unrealized gains or losses in respect of a cross-currency swap derivative instrument that qualifies as a cash flow hedge (net of related tax of $68, $324 and $1,511, respectively)	(1,780)	988	(4,237)

Change in unrealized gains or losses in respect of an interest rate swap derivative instrument that qualifies as a cash flow hedge (net of related tax of $0 for all periods presented)	113	13	—
Other changes in comprehensive income	45	50	53
Comprehensive income	$ 133,803	124,662	129,740
Comprehensive income attributable to noncontrolling interest	(5,306)	(6,328)	(9,173)
Comprehensive income attributable to the Company's stockholders	$ 128,497	$ 118,334	$ 120,567
Earnings per share attributable to the Company's stockholders:			
Basic:	$ 2.04	$ 2.05	$ 2.09
Diluted:	$ 2.02	$ 2.04	$ 2.08
Weighted average number of shares used in computation of earnings per share attributable to the Company's stockholders:			
Basic	60,705	60,455	59,424
Diluted	61,362	60,790	59,762

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	Treasury	Retained	Accumulated Other Comprehensive		Noncontrolling	Total
	Shares	Amount	Capital	Stock	Earnings	Income (Loss)	Total	Interest	Equity
	(Dollars in thousands, except per share data)								
Balance at December 31, 2022	56,096	$ 56	$ 1,259,072	$ (17,964)	$ 623,907	$ 2,500	$ 1,867,571	$ 153,404	$ 2,020,975
Stock-based compensation	—	—	15,478	—	—	—	15,478	—	15,478
Exercise of options by employees and directors (*)	123	—	314	—	—	—	314	—	314
Issuance of common stock	4,140	4	341,667	—	—	—	341,671	—	341,671
Cash paid to noncontrolling interest	—	—	—	—	—	—	—	(7,648)	(7,648)
Cash dividend declared, $0.48 per share	—	—	—	—	(28,412)	—	(28,412)	—	(28,412)
Change in noncontrolling interest rights (net of related tax of $338)	—	—	901		—	—	901	(2,038)	(1,137)
Transaction with noncontrolling interest	—	—	(2,663)	—	—	—	(2,663)	(26,392)	(29,055)
Net income	—	—	—	—	124,399	—	124,399	7,799	132,198
Other comprehensive income (loss), net of related taxes:									
Change in foreign currency translation adjustments	—	—	—	—	—	822	822	435	1,257
Change in unrealized gains or losses in respect of the Company's share in derivative instruments of unconsolidated investment that qualifies as a cash flow hedge	—	—	—	—	—	(470)	(470)	—	(470)
Change in unrealized gains or losses in respect of a cross currency swap derivative instrument that qualifies as a cash flow hedge (net of related tax of $1,511)	—	—	—	—	—	(4,237)	(4,237)	—	(4,237)
Other	—	—	—	—	—	53	53	—	53
Balance at December 31, 2023	$ 60,359	$ 60	$ 1,614,769	$ (17,964)	$ 719,894	$ (1,332)	$ 2,315,427	$ 125,560	$ 2,440,987
Stock-based compensation	—	—	20,197	—	—	—	20,197	—	20,197
Exercise of options by employees and directors (*)	142	1	—	—	—	—	1	—	1
Cash paid to noncontrolling interest	—	—	—	—	—	—	—	(4,707)	(4,707)
Cash dividend declared, $0.48 per share	—	—	—	—	(29,109)	—	(29,109)	—	(29,109)
Buyout of class B membership in OPAL	—	—	279	—	—	—	279	(1,697)	(1,418)
Net income	—	—	—	—	123,733	—	123,733	7,827	131,560
Other comprehensive income (loss), net of related taxes:									
Foreign currency translation adjustments	—	—	—	—	—	(7,052)	(7,052)	(1,180)	(8,232)
Change in unrealized gains or losses in respect of the Company's share in derivative instruments of unconsolidated investment	—	—	—	—	—	602	602	—	602
Change in unrealized gains or losses in respect of a cross currency swap derivative instrument that qualifies as a cash flow hedge (net of related tax of $324)	—	—	—	—	—	988	988	—	988
Change in unrealized gains or losses in respect of interest rate swap derivative instrument that qualifies as a cash flow hedge (net of related tax of $0)	—	—	—		—	13	13	—	13
Other	—	—	—	—	—	50	50	—	50
Balance at December 31, 2024	$ 60,501	$ 61	$ 1,635,245	$ (17,964)	$ 814,518	$ (6,731)	$ 2,425,129	$ 125,803	$ 2,550,932
Stock-based compensation	—	—	19,390	—	—	—	19,390	—	19,390
Exercise of stock-based awards by employees and directors (*)	344	—	—	—	—	—	—	—	—
Cash paid to noncontrolling interest	—	—	—	—	—	—	—	(5,890)	(5,890)
Cash dividend declared, $0.48 per share	—	—	—	—	(29,072)	—	(29,072)	—	(29,072)
Increase in noncontrolling interest related to tax monetization transactions	—	—	—	—	—	—	—	12,059	12,059
Net income	—	—	—	—	123,898	—	123,898	2,745	126,643
Other comprehensive income (loss), net of related taxes:									

Foreign currency translation adjustments	—	—	—	—	—	7,451	7,451	2,214	9,665
Change in unrealized gains or losses in respect of the Company's share in derivative instruments of unconsolidated investment that qualifies as a cash flow hedge	—	—	—	—	—	(1,230)	(1,230)	—	(1,230)
Change in unrealized gains or losses in respect of a cross currency swap derivative instrument that qualifies as a cash flow hedge (net of related tax of $68)	—	—	—	—	—	(1,780)	(1,780)	—	(1,780)
Change in unrealized gains or losses in respect of an interest rate swap derivative instrument that qualifies as a cash flow hedge (net of related tax of $0)	—	—	—	—	—	113	113	—	113
Other	—	—	—	—	—	45	45	—	45
Balance at December 31, 2025	$ 60,845	$ 61	$ 1,654,635	$ (17,964)	$ 909,343	$ (2,132)	$ 2,543,943	$ 136,931	$ 2,680,874

(*) Resulted in an amount lower than $1 thousand.

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,		
	2025	2024	2023
	(Dollars in thousands)		
Cash flows from operating activities:			
Net income	$ 126,990	$ 131,241	$ 133,137
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	292,124	262,863	224,797
Accretion of asset retirement obligation	8,330	7,747	6,164
Stock-based compensation	19,390	20,197	15,478
Income attributable to sale of tax benefits, net of interest expense	(26,252)	(22,145)	(23,462)
Equity in losses (earnings) of investees, net	(960)	425	(35)
Mark-to-market of derivative instruments	550	856	(2,206)
Loss (gain) on disposal of property, plant and equipment	(303)	101	35
Write-off of unsuccessful exploration activities	1,446	3,930	3,733
Impairment of long-lived assets	12,064	1,280	—
Loss (gain) on severance pay fund asset	(294)	(413)	154
Loss (gain) on foreign currency exchange rate	(7,568)	3,428	—
Deferred income tax provision	(33,174)	5,300	(6,017)
Liability for unrecognized tax benefits	4,106	(2,401)	2,114
Changes in operating assets and liabilities, net of businesses acquired:			
Receivables	4,468	27,172	(97,640)
Costs and estimated earnings in excess of billings on uncompleted contracts	(210)	(11,614)	(1,962)
Long-term costs and estimated earnings in excess of billings on uncompleted contracts	(48,930)	(26,033)	—
Inventories	(7,176)	6,945	(22,205)
Prepaid expenses and other	821	(8,510)	(3,248)
Change in operating lease right of use asset	5,093	4,368	3,761
Deposits and other	5,759	(4,491)	(7,900)
Accounts payable and accrued expenses	(1,782)	11,426	68,590
Billings in excess of costs and estimated earnings on uncompleted contracts	(11,322)	5,330	9,884
Liabilities for severance pay	1,454	(1,356)	(989)
Change in operating lease liabilities	(6,387)	(9,472)	(3,435)
Other liabilities, net	(3,136)	4,745	10,653
Net cash provided by operating activities	335,101	410,919	309,401
Cash flows from investing activities:			
Capital expenditures	(619,776)	(487,678)	(618,383)
Investment in unconsolidated companies	(17,796)	(18,969)	(10,181)
Cash paid for acquisition of a business, net of cash acquired	(88,650)	(274,631)	—
Decrease (increase) in severance pay fund asset, net of payments made to retired employees	(213)	1,024	221
Net cash used in investing activities	(726,435)	(780,254)	(628,343)
Cash flows from financing activities:			
Proceeds from long-term loans, net of transaction costs	548,501	514,630	149,837

CONSOLIDATED STATEMENTS OF CASH FLOWS

Proceeds from exercise of options by employees	—	—	314
Proceeds from issuance of common stock, net of stock issuance costs	—	—	341,671
Proceeds from issuance of convertible notes, net of transaction costs	—	44,041	—
Proceeds related to tax monetization transactions	151,986	—	42,329
Proceeds from issuance of commercial paper, net of transaction costs	—	—	99,971
Proceeds from revolving credit lines with banks	1,973,500	185,500	55,000
Repayment of revolving credit lines with banks	(1,893,500)	(205,500)	(35,000)
Cash received from noncontrolling interest	10,276	12,251	7,341
Transaction with noncontrolling interest	—	(9,803)	(30,000)
Repayments of long-term debt and financing liability	(265,462)	(209,280)	(207,039)
Cash paid to noncontrolling interest	(7,834)	(6,373)	(9,856)
Payments under finance lease obligations	(1,840)	(1,383)	(1,963)
Deferred debt and tax monetization transactions issuance costs	(20,809)	(7,058)	(4,229)
Cash dividends paid	(29,072)	(29,109)	(28,412)
Net cash provided by (used in) financing activities	465,746	287,916	379,964
Effect of exchange rate changes on cash and cash equivalents and restricted cash and cash equivalents	682	(579)	72
Net change in cash and cash equivalents and restricted cash and cash equivalents	$ 75,094	$ (81,998)	$ 61,094
Cash and cash equivalents and restricted cash and cash equivalents at beginning of period	205,772	287,770	226,676
Cash and cash equivalents and restricted cash and cash equivalents at end of period	$ 280,866	$ 205,772	$ 287,770
Supplemental disclosure of cash flow information:			
Cash paid during the year for:			
Interest, net of interest capitalized	$ 111,700	$ 102,605	$ 72,236
Income taxes, net of refunds	$ 9,846	$ 26,183	$ 26,250
Supplemental non-cash investing and financing activities:			
Increase (decrease) in accounts payable related to purchases of property, plant and equipment	$ (9,396)	$ (2,501)	$ (12,417)
Right of use assets obtained in exchange for new lease liabilities	$ 15,851	$ 13,360	$ 6,402
Increase in asset retirement cost and asset retirement obligation	$ (5,696)	$ 740	$ 10,546

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 and primarily designs, develops, builds, sells, owns and operates clean, environmentally friendly geothermal power plants, usually using equipment that it designs and manufactures. 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 primarily located in Israel. Additionally, the Company owns and operates independent storage facilities in the United States providing energy storage and related services. 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.

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).

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.

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 and Cash Equivalents

Under the terms of certain long-term debt agreements, the Company is required to maintain certain debt service reserves, including principal and interest, cash collateral and operating fund accounts, including for future wells drilling, which 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, if applicable. Such amounts are 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 sheets that sum to the total of the same amounts shown on the statement of cash flows:

	December 31,		
	2025	2024	2023
	(Dollars in thousands)		
Cash and cash equivalents	$ 147,448	$ 94,395	$ 195,808
Restricted cash and cash equivalents	133,418	111,377	91,962
Total cash and cash equivalents and restricted cash and cash equivalents	$ 280,866	$ 205,772	$ 287,770

Concentration of Credit Risk

Financial instruments which potentially subject the Company to concentration of credit risk consist principally of temporary cash investments, accounts receivable, and the cross-currency and interest rate swap transactions.

Cash Investments:

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, 2025 and 2024, the Company had deposits totaling $83.6 million and $31.2 million, respectively, in ten United States financial institutions that were federally insured up to $250,000 per account. At December 31, 2025 and 2024, the Company's deposits in foreign countries of approximately $75.4 million and $73.9 million, respectively, were not insured.

Account Receivables:

At December 31, 2025 and 2024, accounts receivable related to operations in foreign countries amounted to approximately $102.0 million and $105.2 million, respectively. At December 31, 2025 and 2024, accounts receivable from the Company's major customers (see Note 17) amounted to approximately 56% and 57%, respectively, of the Company's accounts receivable. The aggregate amount of notes receivable exceeding 10% of total receivables for the year ended December 31, 2025 and 2024 is $103.2 million and $99.7 million, respectively.

The Company has historically been able to collect substantially all of its receivable balances. As of December 31, 2025, the amount overdue from KPLC in Kenya was $29.5 million of which $21.1 million was paid in January and February of 2026. The Company believes it will be able to collect all past due amounts in Kenya. This belief is supported by the fact that in addition to KPLC's obligations under its power purchase agreement, the Company holds a support letter from the Government of Kenya that covers certain cases of KPLC non-payment (such as non-payments that are caused by government actions and/or political events).

In Honduras, as of December 31, 2025, the total amount overdue from ENEE was $20.3 million of which $1.0 million was collected in January and February of 2026. In addition, due to the financial situation in Honduras, the Company may experience additional delays in collection. The Company believes it will be able to collect all past due amounts in Honduras.

Additionally, the Company considers the counterparty credit risk related to the cross-currency and interest rate swap transactions, as further described in note 11 to the consolidated financial statements, when assessing the hedge effectiveness, noting such risk to be low as of December 31, 2025.

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, 2025 and 2024.

Deposits and Other

Deposits and other consist primarily of performance bonds for construction and storage projects, long-term insurance contract funds and receivables, certain deferred costs and deferred financing costs, long-term derivative assets and long-term costs and estimated earnings in excess of billings on uncompleted contracts related to the Dominica project.

Property, Plant and Equipment, Net

Property, plant and equipment are stated at cost, (except when acquired as part of a business combination, as further described under Note 2 to the consolidated financial statements), net of accumulated depreciation. 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:

	Years
Buildings	25
Leasehold improvements	15 - 30
Machinery and equipment — manufacturing and drilling	5 - 10
Machinery and equipment — computers	3 - 5
Energy storage equipment	8 - 20
Solar facility equipment	30
Office equipment — furniture and fixtures	5 - 15
Office equipment — other	5 - 10
Vehicles	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 $28.1 million, $14.7 million, and $17.3 million for the years ended December 31, 2025, 2024 and 2023, 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, 2025, 2024 and 2023. 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 land lease payments made during the exploration, development and construction phase are accounted under lease accounting as further described under the caption Leases below and reflected as expenses under "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. During the years ended December 31, 2025, 2024 and 2023, the Company recorded $1.4 million, $3.9 million, and $3.7 million of unsuccessful exploration and storage activities, respectively, that the Company decided to no longer pursue, out of which $1.4 million, $2.0 million and $0.3 million, respectively, relate to storage activities that the Company decided to no longer pursue.

All exploration and development costs that are being capitalized 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 and storage 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 reassesses 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 "Deposits and other" 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). Amortization expense for the years ended December 31, 2025, 2024 and 2023 amounted to $6.4 million, $5.9 million, and $5.9 million, respectively. During the years ended December 31, 2025, 2024 and 2023, no material amounts 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 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, which the Company performs 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, it 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 the quantitative goodwill impairment test. This would not preclude the entity from performing the qualitative assessment in any subsequent period. The quantitative assessment compares the fair value of the reporting unit to its carrying value, including goodwill. Under ASU 2017-04, Intangibles – Goodwill and Other (Topic 350), an entity should recognize an impairment charge for the amount by which the carrying amount of the reporting unit exceeds its fair value. 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 4 to 19-year terms of the agreements (see Note 9) as well as acquisition costs allocation related to the Company's Energy Storage segment activities that are amortized over a period of between approximately 6 and 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 are no such events or change in circumstances, there is no need to perform an 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 of 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. Management believes that as of December 31, 2025, no impairment exists for long-lived assets, except as described below. 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.

As further described under Note 8 to the consolidated financial statements, in the fourth quarter of 2025, the Company recorded a non-cash impairment charge of $12.1 million in respect of its Brawley power plant and OREG 2 facility. This charge was recorded under "Impairment of long-lived assets" line item in the consolidated statements of operations and comprehensive income (loss).

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. Changes in the fair value of derivatives not designated as hedging instruments are recognized in earnings. Changes in the fair value of derivatives designated as cash flow hedging instruments are initially recorded in "Other comprehensive income (loss)" and a corresponding amount is reclassified out of "Accumulated other comprehensive income (loss)" into earnings to offset the impact of the underlying hedge transaction when it affects earnings under the same line item in the consolidated statements of operations and comprehensive income.

The Company maintains a risk management strategy that may incorporate the use of swap contracts, put options, forward exchange contracts, interest rate swaps, and cross-currency swaps 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.

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 the Guadeloupe power plant and the Company's operations in New Zealand. For those U.S. dollar functional currency entities, all gains and losses from currency translations are included under "Derivatives and foreign currency transaction gains (losses)" in the consolidated statements of operations and comprehensive income (loss). The Euro and New Zealand Dollar are the functional currencies of the Company's operations in Guadeloupe and New Zealand, respectively, and thus the impact from currency translation adjustments related to those locations is 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 a debit of $1.9 million and a debit of $9.3 million, as of December 31, 2025 and 2024, respectively.

Comprehensive Income

Comprehensive income includes net income plus other comprehensive income (loss), which for the Company consists primarily of changes in foreign currency translation adjustments, changes in unrealized gains or losses in respect of the Company's share in derivatives instruments of an unconsolidated investment that qualifies as a cash flow hedge, and changes in respect of derivative instruments designated as a cash flow hedge. The changes in foreign currency translation adjustments included under other comprehensive income (loss) during the years ended December 31, 2025, 2024 and 2023 amounted to $9.7 million, $(8.2) million, and $1.3 million, respectively. The changes in the Company's share in derivative instruments of an unconsolidated investment, and gains or losses in respect of derivative instruments designated as a cash flow hedge are disclosed under Note 5 – Investment in unconsolidated companies, and Note 7 - Fair value of financial instruments, respectively, to the consolidated financial statements.

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 2025 to 2051.

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. One of the Company's subsidiaries in Guatemala sells power at an agreed upon price subject to terms of a "take or pay" PPA.

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.

Revenues and Cost of Revenues

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 sale, engineering, construction and installation, and operating services; and (iii) sale of capacity, energy and/or ancillary services from its energy storage facilities.

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. The Company assesses whether PPAs entered into, modified, or acquired in business combinations contain a lease element requiring lease accounting. Revenue from such PPAs are accounted for in electricity revenues. In the Electricity segment, revenues for all but thirteen 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, Revenue from Contracts with Customers ("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 represents 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 the Company performs 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 Segment Revenues:

Battery energy storage systems as a service, and 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 except for three storage facilities of which revenues are accounted as operating leases under lease accounting, 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.

Contract Assets and Contract Liabilities

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 customer billing 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, 2025 and 2024 are as follows:

	December 31,	
	2025	2024
	(Dollars in thousands)	
Contract assets (*)	$ 30,011	$ 29,243
Contract liabilities (*)	$ (13,159)	$ (23,091)

(*) 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 substantially recognized as product revenues during the year ended December 31, 2025 as a result of performance obligations that were satisfied. Additionally, as of December 31, 2025 and 2024, long-term costs and estimated earnings in excess of billings on uncompleted contracts related to the Dominica project in the amount of $75.0 million and $26.0 million, respectively, are included under “Deposits and other” in the consolidated balance sheets, and not under the contract assets and contract liabilities above, due to their long-term nature. Further details related to the Dominica Project are provided below under the caption “The Dominica Project”.

The following table presents the significant changes in the contract assets and contract liabilities for the years ended December 31, 2025 and 2024:

	Years Ended December 31,			
	2025		2024	
	Contract assets	Contract liabilities	Contract assets	Contract liabilities
	(Dollars in thousands)			
Recognition of contract liabilities as revenue as a result of performance obligations satisfied	$ —	$ 21,478	$ —	$ 12,698

Cash received in advance for which revenues have not yet recognized, net of expenditures made	—	(11,546)	—	(17,119)
Reduction of contract assets as a result of rights to consideration becoming unconditional	(19,774)	—	(5,070)	—
Contract assets recognized, net of recognized receivables	20,542	—	15,945	—
Net change in contract assets and contract liabilities	$ 768	$ 9,932	$ 10,875	$ (4,421)

The timing of revenue recognition, billings and cash collections result 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, 2025, the Company had approximately $245.0 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 revenues accounted under ASC 606, Revenues from Contracts with Customers, to total consolidated revenues for the three years ended December 31, 2025, 2024 and 2023:

	Year Ended December 31,		
	2025	2024	2023
	(Dollars in thousands)		
Electricity and Energy Storage revenues accounted under lease accounting	$ 569,120	$ 553,348	$ 542,065
Electricity, Product and Energy Storage revenues accounted under ASC 606	420,423	326,306	287,359
Total consolidated revenues	$ 989,543	$ 879,654	$ 829,424

Disaggregated revenues from contracts with customers for the years ended December 31, 2025, 2024, and 2023 are disclosed under Note 17 - Business Segments, to the consolidated financial statements.

The Dominica Project

In December 2023, the Company entered into agreements with the Commonwealth of Dominica to build and operate a 10 MW binary geothermal power plant in the Caribbean country of Dominica. Under these agreements, the Company will construct the power plant, operate and sell its generated energy to Dominica Electricity Services Limited (presently the only electricity utility in the Commonwealth of Dominica) over a period of 25 years, at the end of which, ownership of the power plant will be transferred to the Government of the Commonwealth of Dominica. The Company accounted for this transaction under the guidance of ASC 853, Service Concession Arrangements (“ASC 853”), which directs a reporting entity to apply ASC 606, Revenue from Contracts with Customers.

Under the aforementioned accounting guidance, the Company identified the construction and the operation of the power plant as two distinct performance obligations, and accordingly allocated the total transaction price to these separate performance obligations in the arrangement, based on their estimated stand-alone selling price. The Company concluded that the performance obligations are satisfied over time. Additionally, starting the second quarter of 2024, in conjunction with the power plant start of construction, the Company started recognizing revenues relating to the construction performance obligation based on an input method using costs incurred to total costs expected in the project. Such revenues are included under Product revenues in the consolidated statements of operations and comprehensive income.

Allowance for Credit Losses

The Company performs an analysis of potential credit losses related to its financial instruments that are within the scope of ASU 2018-19, Codification Improvements to Topic 325, Financial Instruments – Credit Losses. Such instruments are primarily cash and cash equivalents, restricted cash and cash equivalents, receivables (excluding those accounted under lease accounting) and costs and estimated earnings in excess of billings on uncompleted contracts, based on class of financing receivables which share the same or similar risk characteristics such as customer type and geographic location, among others. The Company estimates the expected credit losses for each class of financing receivables by applying the related corporate default rate which corresponds to the credit rating of the specific customer or class of financing receivables. For trade receivables, the Company applied this methodology using aging schedules reflecting how long the receivables have been outstanding. The Company has also considered the existence of credit enhancement arrangements that may mitigate the credit risk of its financial receivables in estimating the applicable corporate default

rate. The Company considered the current and expected future economic and market conditions related to inflation and rising interest rates and determined that the estimate of credit losses was not significantly impacted.

The following table describes the changes in the allowance for expected credit losses for the years ended December 31, 2025 and 2024 (all related to trade receivables):

	Years Ended December 31,	
	2025	2024
	(Dollars in thousands)	
Beginning balance of the allowance for expected credit losses	$ 224	$ 90
Change in the provision for expected credit losses for the period	84	134
Ending balance of the allowance for expected credit losses	$ 308	$ 224

Leases

ASU 2016-02, Leases (Topic 842), defines 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 is a lessee in operating lease transactions primarily consisting of land leases for its exploration and development activities in the Electricity segment. The Company is also a lessee in finance lease transactions related to its fleet vehicles in the U.S. Additionally, one of the Company's power plant assets which was included in the Terra-Gen business acquisition in 2021, is subject to a sale and leaseback transaction that is accounted as a "failed" sale and leaseback. Additionally, 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 lease 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.

The Company, both as a lessee and as a lessor, applies the following permitted practical expedients:

1. Not reassess whether any existing contracts are or contain a lease;
2. Applying the practical expedient for a lessee to not separate non-lease components from lease components and, instead, to account for each separate lease component and the non-lease components associated with that lease as a single component;
3. 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 continued to recognize the lease payments for those leases in profit or loss on a straight-line basis over the lease term.

The Company applies the following significant accounting policies regarding leases it enters into following the adoption of the lease guidance on January 1, 2019:

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 on 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 recognizes 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 lease payments made during the period. The Company determines 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. The amortization period related to the finance lease transactions on fleet vehicles is 4-5 years. 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 may include variability and depend on an index or a rate (such as the Consumer Price Index or a market interest rate). 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 depend 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, however, the Company has no such leases as a lessor. Under an operating lease, the Company recognizes the lease payment as income over the lease term, generally as earned or on a straight-line basis.

Termination Fee

Fees to terminate PPAs are recognized in the period incurred as selling and marketing expenses. No termination fees were incurred during 2025, 2024 and 2023.

Warranty on Products Sold

The Company generally provides a one to two year 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, 2025, 2024 and 2023.

Research and Development

Research and development costs incurred by the Company for the development of technologies related to its existing and new geothermal and recovered energy power plants as well as its storage facilities are expensed as incurred.

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 Black-Merton-Scholes using binomial Tree option pricing model to calculate the fair value of the stock-based compensation awards.

Tax Monetization Transactions

The Company has the following seven tax monetization transactions: Tungsten, McGinness Hills 3, Steamboat Hills, CD4, North Valley, Heber 1 and 2 and two hybrid tax equity partnerships as further described under Note 12 – Tax Monetization Transactions. 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. Except for the hybrid tax equity partnerships, 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 at 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 the sale of 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 are capitalized and amortized using the effective interest method.

As further detailed under Note 12 – Tax Monetization Transactions, the Company accounts for ITCs under ASC 740 through the “Income tax (provision) benefit” line in the consolidated statement of operations and comprehensive income. As such, income related to the ITCs associated with the Lower Rio and Arrowleaf storage facilities that are included in the hybrid tax equity partnership, was included under the “Income tax (provision) benefit” line in the consolidated statement of operations and comprehensive income. Proceeds allocated to other tax attributes, will be included under “Income attributable to the sale of tax benefits” line in the consolidated statement of operations and comprehensive income. Noncontrolling interest is recorded in the same manner described above, as a portion of the transaction is structured as a purchase of an equity interest, consistent with guidance in ASC 810.

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 (except for production tax credits which are sold under tax monetization transactions, as described above) 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 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 attributable to the Company’s stockholders by the weighted average number of shares of common stock outstanding for the period, net of treasury shares. The Company does not have any equity instruments that are dilutive, except for stock-based awards and convertible senior notes.

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,		
	2025	2024	2023
	(In thousands)		
Weighted average number of shares used in computation of basic earnings per share	60,705	60,455	59,424

Add:			
Additional shares from the assumed exercise of employee stock-based awards	427	335	338
Additional shares related to the effect of dilutive convertible senior notes	230	—	—
Weighted average number of shares used in computation of diluted earnings per share	61,362	60,790	59,762

The number of stock-based awards that could potentially dilute future earnings per share which were not included in the computation of diluted earnings per share because to do so would have been anti-dilutive was 2.1 thousand, 38.5 thousand, and 82.5 thousand, respectively, for the years ended December 31, 2025, 2024 and 2023.

Redeemable Noncontrolling Interest

Redeemable noncontrolling interest is currently redeemable and relates to a certain noncontrolling shareholder in a subsidiary having an option to sell its equity interest to the Company. The carrying value of the redeemable noncontrolling interest balance as of December 31, 2025 and 2024 approximates the redemption price of such interests. Changes in the carrying amount of the Company's Redeemable noncontrolling interest were as follows:

	2025	2024
	(Dollars in thousands)	
Redeemable noncontrolling interest as of January 1,	$ 9,448	$ 10,599
Redeemable noncontrolling interest in results of operation of a consolidated subsidiary	347	(319)
Cash paid to noncontrolling interest	(956)	—
Currency translation adjustments	1,563	(832)
Redeemable noncontrolling interest as of December 31,	$ 10,402	$ 9,448

Cash Dividends

During the years ended December 31, 2025, 2024 and 2023, the Company's Board of Directors (the "Board") declared, approved, and authorized the payment of cash dividends in the aggregate amount of $29.1 million ($0.48 per share), $29.1 million ($0.48 per share), and $28.4 million ($0.48 per share), respectively. Such dividends were paid in the years declared.

TOPP2 Power Plant in New Zealand

In May 2023, the Company signed with Eastland Generation Limited ("EGL") agreements governing the development, supply, construction, and option to sell the TOPP2 power plant in New Zealand. In August 2025, the Company received an option exercise notice (the "Notice") from EGL pursuant to which EGL wishes to acquire the TOPP2 power plant in New Zealand pursuant to a previously signed option agreement between the Company and EGL (the "Parties"). During the first quarter of 2026, the Parties signed and closed the sale agreement and amended the previously signed agreements governing the development, supply, construction, and sale of the TOPP2 power plant. The Company applied the guidance in Accounting Standard Codification 606 - Revenue from Contracts with Customers ("ASC 606") to this transaction, under which several criteria must be met before a reporting entity can recognize revenue from contracts with customers. The Company concluded that as of December 31, 2025, not all required criteria for identifying a contract have been met, including but not limited to the Parties being required to sign and close on a sale agreement following the Notice. As a result, the Company did not record any revenues from this transaction in 2025. The Company is currently evaluating the accounting for this transaction, following the close of the sale agreement and the amendments to the development, supply and construction agreements of the TOPP2 power plant.

Settlement Agreement

As previously disclosed, on August 1, 2024, the Company entered into a settlement agreement, effective April 2024, (the "Agreement") with a third-party battery systems supplier (the "Supplier"). Under the Agreement, the Supplier paid to the Company $35.0 million as a recovery of damages, such as significant loss of potential profit due to project delays, as well as additional costs incurred by the Company, related to locating and purchasing substitute battery solutions from alternative vendors (the "Recovery of Damages"), to settle the dispute. On August 16, 2024, the Company received the Recovery of Damages payment contingent upon certain conditions which the Company expects to be met, on a pro-rata basis, during the period until March 31, 2026. The Company accounted for the Recovery of Damages amount under the guidance of ASC 450, Contingencies, and ASC 705, Cost of Sales and Services, and as a result, deemed $25.0 million as a recovery of damages, which is recognized as income once contingency conditions are met, and $10.0 million as a reduction to the cost of battery systems to be purchased under the Agreement. During the years ended December 31, 2025 and 2024, the Company recognized income of $13.7 million, and $9.4 million, respectively. Such income was recorded under "Other operating income" in the consolidated statements of operations and comprehensive income. These amounts represent the non-refundable portion of the recovery of damages for which contingency conditions have been met.

New Accounting Pronouncements

New Accounting Pronouncements Effective in the Year Ended December 31, 2025

Improvements to Income Tax Disclosures

In December 2023, the FASB issued ASU 2023-09 "Income Taxes (Topic 740)–Improvements to Income Tax Disclosures" to enhance the transparency and decision usefulness of income tax disclosures, primarily related to the rate reconciliation and income taxes paid information. The amendments in this ASU require that public entities, on an annual basis, disclose specific categories in the rate reconciliation and provide additional information for reconciling items that meet a quantitative threshold. This ASU also requires that all entities disclose, on an annual basis, (1) the amount of income taxes paid disaggregated by federal, state, and foreign taxes, (2) the amount of income taxes paid disaggregated by individual jurisdictions in which income taxes paid is equal to or greater than five percent of total income taxes paid, (3) income or loss from continuing operations before income tax expense or benefit disaggregated between domestic and foreign, and (4) income tax expense or benefit from continuing operations disaggregated by federal, state, and foreign. The amendments in this ASU are effective for annual periods beginning after December 15, 2024, and should be applied on a prospective basis with the option to apply retrospectively. The Company has adopted this guidance as prescribed and applied the changes on a retrospective basis.

New Accounting Pronouncements Effective in Future Periods

Narrow-Scope Improvements

In December 2025, the FASB issued ASU 2025-11 "Interim Reporting (Topic 270)" to improve the navigability of required interim disclosures, clarify when that guidance is applicable, and provide additional guidance on what disclosures should be provided in interim reporting periods. The amendments provide a comprehensive list of required interim disclosures and add a principle that requires entities to disclose events since the end of the last annual reporting period that have a material impact on the entity. This ASU is not intended to change the fundamental nature of interim reporting or expand or reduce current interim reporting requirements. Rather, the objective of this ASU is to provide clarity regarding current interim reporting requirements already in place. This ASU is effective for interim reporting periods within annual reporting periods beginning after December 15, 2027. Early adoption is permitted. This ASU should be applied either prospectively or retrospectively to all prior periods presented. The Company anticipates that the adoption of this ASU will not have a material impact on its consolidated financial statements.

Accounting for Government Grants Received by Business Entities

In December 2025, the FASB issued ASU 2025-10 "Government Grants (Topic 832)" to establish authoritative guidance on the accounting for government grants received by business entities, including guidance for a grant related to an asset and a grant related to income. The overall principle is that a government grant is recognized in earnings in the same period(s) that the costs for which the grant was intended to compensate are recognized. A grant related to an asset is a government grant, or part of a government grant, that is conditioned on the purchase, construction, or acquisition of an asset. A grant related to income is a government grant, or part of a government grant, other than a grant related to an asset. The amendments in this ASU require that a government grant received by a business entity should not be recognized until it is probable that a business entity will comply with the conditions attached to the grant and that the grant will be received.

A grant related to an asset should be recognized on the balance sheet as a business entity incurs the related costs for which the grant is intended to compensate, either as: a. deferred income (the deferred income approach) or b. an adjustment to the cost basis in determining the carrying amount of the asset (the cost accumulation approach).

A grant related to income and a grant related to an asset for which the deferred income approach is elected should be recognized in earnings on a systematic and rational basis over the periods in which a business entity recognizes as expenses the costs for which the grant is intended to compensate. When a business entity elects the cost accumulation approach for a grant related to an asset, there is no separate subsequent recognition of the government grant proceeds in earnings as the carrying amount of the asset that reflects the government grant proceeds would be used to determine depreciation or other subsequent accounting for that asset.

This ASU is effective for annual reporting periods beginning after December 15, 2028, and interim reporting periods within those annual reporting periods. Early adoption is permitted. Business entities should apply the amendments in this ASU using one of the following transition approaches:

1. A modified prospective approach to both government grants that are entered into on or after the effective date and government grants that are not complete as of the effective date. Under this approach, prior-period results should not be restated and there is no cumulative-effect adjustment.
2. A modified retrospective approach to both government grants that are entered into on or after the beginning of the earliest period presented and government grants that are not complete as of the beginning of the earliest period presented. Under this approach, all prior period results should be restated for government grants that are not complete as of the beginning of the

earliest period presented through a cumulative-effect adjustment to the opening balance of retained earnings as of the beginning of the earliest period presented.

3. A retrospective approach to all government grants through a cumulative-effect adjustment to the opening balance of retained earnings as of the beginning of the earliest period presented.

The Company is currently evaluating the potential impact of this guidance on its consolidated financial statements, however, it anticipates that the adoption of this ASU will not have a material impact on its consolidated financial statements.

Hedge Accounting Improvements

In November 2025, the FASB issued ASU 2025-09 "Derivatives and Hedging (Topic 815)" to clarify certain aspects of the guidance on hedge accounting and to better reflect an entity's risk management strategies in financial reporting by enabling entities to achieve and maintain hedge accounting for highly effective economic hedges of forecasted transactions. This ASU addresses the following five issues:

1. Similar Risk Assessment for Cash Flow Hedges – This ASU expands the hedged risks permitted to be aggregated in a group of individual forecasted transactions in a cash flow hedge by changing the requirement to designate a group of individual forecasted transactions from having a shared risk exposure to having a similar risk exposure.
2. Hedging Forecasted Interest Payments on Choose-Your-Rate Debt Instruments – This ASU provides a model to facilitate the application of cash flow hedge accounting to forecasted interest payments on variable-rate debt instruments with contractual terms that permit the borrower to change the interest rate index and related payment frequency upon which interest is accrued (commonly referred to as "choose-your-rate" debt instruments).
3. Cash Flow Hedges of Nonfinancial Forecasted Transactions – This ASU expands hedge accounting for forecasted purchases and sales of nonfinancial assets. Subject to meeting specific criteria, entities are permitted to apply hedge accounting for eligible components of forecasted spot-market transactions, forward-market transactions, and subcomponents of explicitly referenced components in an agreement's pricing formula. The amendments also clarify that entities may designate a variable price component in a contract that is accounted for as a derivative as the hedged risk if all other hedge criteria are satisfied.
4. Net Written Options as Hedging Instruments – This ASU updates hedge accounting guidance to accommodate differences in the loan and swap markets that developed after the cessation of the London Interbank Offered Rate (LIBOR). The amendments eliminate the requirement to apply the net written option test to a compound derivative comprising a swap and a written option designated as the hedging instrument in a cash flow hedge or a fair value hedge of interest rate risk.
5. Foreign-Currency-Denominated Debt Instrument as Hedging Instrument and Hedged Item (Dual Hedge) – This ASU eliminates the recognition and presentation mismatch related to a dual hedge strategy (i.e., a hedge for which a foreign-currency-denominated debt instrument is both designated as the hedging instrument in a net investment hedge and designated as the hedged item in a fair value hedge of interest rate risk). The amendments require that an entity exclude the debt instrument's fair value hedge basis adjustment from the net investment hedge effectiveness assessment, resulting in an entity immediately recognizing in earnings the gains and losses from the remeasurement of the debt instrument's fair value hedge basis adjustment at the spot exchange rate.

This ASU is effective for annual reporting periods beginning after December 15, 2026, and interim reporting periods within those annual reporting periods. Early adoption is permitted. This ASU should be applied prospectively for all hedging relationships. Upon adoption of this ASU, entities are permitted to modify certain critical terms of certain existing hedging relationships without de-designating the hedge. The Company is currently evaluating the potential impact of this guidance on its consolidated financial statements, however, it anticipates that the adoption of this ASU will not have a material impact on its consolidated financial statements.

Derivatives Scope Refinements and Scope Clarification for Share-Based Noncash Consideration from a Customer in a Revenue Contract

In September 2025, the FASB issued ASU 2025-07 "Derivatives and Hedging (Topic 815) and Revenue from Contracts with Customers (Topic 606)" to address concerns about (1) the application of derivative accounting to contracts with features based on the operations or activities of one of the parties to the contract and (2) the diversity in accounting for share-based noncash consideration from a customer that is consideration for the transfer of goods or services. The amendments in this ASU expand the scope exception for application of derivative accounting for certain contracts not traded on an exchange to include contracts for which settlement is based on operations or activities specific to one of the parties to the contract. The amendments in this ASU also clarify that an entity should apply the guidance in Topic 606 to a contract with share-based noncash consideration from a customer for the transfer of goods or services. This ASU is effective for annual reporting periods beginning after December 15, 2026, and interim reporting periods within those annual reporting periods. Early adoption is permitted. This ASU may be applied prospectively or on a modified retrospective basis. The Company is currently evaluating the potential impact of this guidance on its consolidated financial

statements; however, it anticipates that the adoption of this ASU will not have a material impact on its consolidated financial statements.

Measurement of Credit Losses for Accounts Receivable and Contract Assets

In July 2025, the FASB issued ASU 2025-05 "Financial Instruments – Credit Losses (Topic 326)" to address challenges encountered when applying the guidance in Topic 326 to current accounts receivable and current contract assets arising from transactions accounted for under Topic 606, Revenue from Contracts with Customers. Under the current accounting guidance, an entity estimates expected credit losses based on relevant information about past events, current economic conditions, and reasonable and supportable forecasts of future economic conditions that affect the collectability of the reported amounts. The amendments in this ASU introduce a practical expedient that allows all entities to assume that current conditions as of the balance sheet date do not change for the remaining life of the asset when developing reasonable and supportable forecasts as part of estimating expected credit losses. This ASU is effective for annual reporting periods beginning after December 15, 2025, and interim reporting periods within those annual reporting periods. This ASU should be applied on a prospective basis. Early adoption is permitted. The Company is currently evaluating the potential impact of this guidance on its consolidated financial statements, however, it anticipates that the adoption of ASU 2025-05 will not have a material impact on its consolidated financial statements.

Determining the Accounting Acquirer in the Acquisition of a Variable Interest Entity

In May 2025, the FASB issued ASU 2025-03 "Business Combinations (Topic 805) and Consolidation (Topic 810)" to modify the Topic 805 framework for identifying the accounting acquirer in certain business combinations when the legal acquiree is a variable interest entity ("VIE"). Under current accounting guidance, when a VIE is acquired, the primary beneficiary (i.e., the entity that consolidates the VIE) is the accounting acquirer. The amendments in this ASU revise current guidance to: (1) limit situations in which entities must identify the primary beneficiary as the accounting acquirer in certain business combinations, and (2) require that when a business combination involving a VIE is primarily effected through exchanging equity interests, entities must consider the general factors in Topic 805 to determine which entity is the accounting acquirer. This ASU is effective for annual and interim reporting periods beginning after December 15, 2026. This ASU should be applied prospectively to any acquisition transaction that occurs after the initial application date. Early adoption is permitted as of the beginning of an interim or annual reporting period. The Company is currently evaluating the potential impact of this guidance on its consolidated financial statements; however, it anticipates that the adoption of ASU 2025-03 will not have a material impact on its consolidated financial statements.

Disaggregation of Income Statement Expenses

In November 2024, the FASB issued ASU 2024-03 "Income Statement – Reporting Comprehensive Income – Expense Disaggregation Disclosures (Subtopic 220-40)" to improve the disclosure about a public business entity's expenses and address requests from investors for more detailed information about the types of expenses in commonly presented expense captions. The amendments in this ASU require disclosure of the following items in the notes to the financial statements at each interim and annual reporting date:

1 The amounts of (a) purchases of inventory, (b) employee compensation, (c) depreciation, (d) intangible asset amortization, and (e) depreciation, depletion, and amortization recognized as part of oil- and gas-producing activities included in each relevant expense caption. A relevant expense caption is an expense caption presented on the face of the income statement within continuing operations that contain any of the expense categories listed in (a) through (e).

2 A qualitative description of the amounts remaining in relevant expense captions that are not separately disaggregated quantitatively.

3 The total amount of selling expenses recognized in continuing operations, and the entity's definition of selling expenses.

The amendments of this ASU also require that an entity include certain amounts that are already required to be disclosed under current generally accepted accounting principles in the same disclosure as the other disaggregation requirements. The amendments in this ASU are effective for annual periods beginning after December 15, 2026, and interim reporting periods beginning after December 15, 2027, and should be applied either (1) prospectively to financial statements issued for reporting periods after the effective date of the ASU or (2) retrospectively to any or all prior periods presented in the financial statements. Early adoption is permitted. The Company is currently evaluating the impact of the adoption of these amendments on its consolidated financial statements.

Induced Conversions of Convertible Debt Instruments

In November 2024, the FASB issued ASU 2024-04 "Debt – Debt with Conversion and Other Options (Subtopic 470-20)" to improve the relevance and consistency in application of induced conversion guidance. The amendments in this ASU clarify the assessment of whether a transaction should be accounted for as an induced conversion or extinguishment of convertible debt when changes are made to conversion features as part of an offer to settle the instrument. This ASU is effective for annual reporting periods beginning after December 15, 2025, and interim reporting periods within those annual reporting periods. This ASU can be adopted either on a prospective or retrospective basis. Early adoption is permitted. The Company is currently evaluating the potential impact

of this guidance on its consolidated financial statements; however, it anticipates that the adoption of ASU 2024-04 will not have a material impact on its consolidated financial statements.

NOTE 2 — BUSINESS ACQUISITIONS

Blue Mountain Purchase Transaction

On June 18, 2025, the Company closed a purchase transaction with Cyrq Energy to acquire 100% ownership of the Blue Mountain geothermal power plant for a total consideration of $88.7 million (including customary post-closing working capital adjustments). The Blue Mountain power plant is a 20MW facility, located in Humboldt County, NV, under a Power Purchase Agreement (the "PPA") with NV Energy that expires at the end of 2029.

As a result of the acquisition, the Company expanded its overall generation capacity and expects to improve the profitability of the power plant through cost reduction, synergies and upgrades. The Company accounted for the transaction in accordance with Accounting Standard Codification ("ASC") 805, Business Combinations, and following the transaction, the Company consolidates the power plant in accordance with ASC 810, Consolidation.

During the year ended December 31, 2025, the Company incurred $1.2 million of acquisition- related costs. Such costs are included under "General and administrative expenses" in the consolidated statements of operations and comprehensive income for the respective periods. The following table summarizes the purchase price allocation to the fair value of the assets acquired and liabilities assumed (in millions):

Trade receivables and others [1]	$	1.7
Deferred income taxes		5.0
Property, plant and equipment and construction-in-process [2]		86.2
Operating lease right-of-use		1.4
Total assets acquired	$	94.3
Accounts payable, accrued expenses and others	$	0.3
Long-term operating lease liabilities		1.2
Other long-term liability [3]		16.8
Asset retirement obligation		3.7
Total liabilities assumed	$	22.0
Total assets acquired, and liabilities assumed, net	$	72.3
Goodwill [4]	$	16.4

[1] The gross amount of trade receivables was collected subsequent to the acquisition date.

[2] The fair value of Property, plant and equipment was estimated by applying the income approach and utilizing the discounted cash flow method. This methodology assesses the value of tangible assets by computing the anticipated cash flows expected to be generated by the respective assets.

[3] Other long-term liability is related to the long-term electricity PPA described above, and is amortized over the term of the PPA. The fair value of the long-term liability represents a PPA price that is relatively lower than the related prevailing market price, and was estimated by applying the income approach and utilizing the With and Without method.

[4] Goodwill is primarily related to the expected synergies, potential cost savings in operations as a result of the purchase transaction as well as potential future enhancements to the geothermal assets. The goodwill is allocated to the Electricity segment and is deductible for tax purposes.

During the year ended December 31, 2025, the acquired power plant contributed $6.6 million to the Company's Electricity revenues, and $4.1 million to the Company's earnings which were included in the Company's consolidated statements of operations and comprehensive income for that period. Pro forma information is not provided as the Company deemed this information to be immaterial.

Business Combination - Enel Purchase Transaction

On January 4, 2024, the Company closed a purchase transaction with Enel Green Power North America ("EGPNA"), a subsidiary of Enel SpA (ENEL.MI) to acquire a portfolio of assets which includes two contracted geothermal power plants, one triple hybrid power plant which consists of geothermal, solar PV, and solar thermal units, two stand-alone solar power plants, and two greenfield development assets, for a total cash consideration of $274.6 million (including customary post-

closing working capital adjustment to the purchase price, based on the levels of net working capital of the acquired companies) for 100% of the equity interests in the entities holding those assets.

The geothermal power plants include the Cove Fort power plant located in Beaver County, Utah, which sells electricity under a long-term power purchase agreement (“PPA”) with Salt River Project, and the Salt Wells power plant located in Churchill County, Nevada, which sells electricity under a long-term PPA with NV Energy. The Stillwater triple hybrid geothermal, solar PV and solar thermal power plant is located in Churchill County, Nevada, and sells electricity to NV Energy under a PPA. The solar assets of Stillwater solar PV II in Churchill County, Nevada, and Woods Hill in Windham County, Connecticut, sell their electricity under PPAs, respectively.

As a result of the acquisition, the Company expanded its overall generation capacity and expects to improve the profitability of the purchased assets through cost reduction, synergies and development of the greenfield assets. The Company accounted for the transaction in accordance with Accounting Standard Codification ("ASC") 805, Business Combinations, and following the transaction, the Company consolidates the power plants and all other assets included in the transaction in accordance with ASC 810, Consolidation.

During 2024 and 2023, the Company incurred $1.3 million, and $1.1 million of acquisition-related costs, respectively. Such costs are included under "General and administrative expenses" in the consolidated statements of operations and comprehensive income for the respective periods.

The following table summarizes the purchase price allocation to the fair value of the assets acquired and liabilities assumed (in millions):

Trade receivables and others [1]	$	4.4
Deferred income taxes		2.9
Property, plant and equipment and construction-in-process [2]		197.7
Operating lease right of use		1.2
Other long-term assets		0.2
Intangible assets [3]		23.6
Total assets acquired	$	230.0
Accounts payable, accrued expenses and others	$	1.5
Other current liabilities		1.8
Operating lease liabilities		1.2
Other long-term liabilities		5.0
Asset retirement obligation		6.8
Total liabilities assumed	$	16.3
Total assets acquired, and liabilities assumed, net	$	213.7
Goodwill [4]	$	60.9

[1] The gross amount of trade receivables was fully collected subsequent to acquisition date.

[2] The fair value of Property, plant and equipment was estimated by applying the income approach and utilizing the discounted cash flow method. This methodology assesses the value of tangible assets by computing the anticipated cash flows expected to be generated by the respective assets.

[3] Intangible assets are related to the long-term electricity PPAs described above and are amortized over the term of those PPAs. The fair value of the intangible assets was estimated by applying the income approach and utilizing the With and Without method.

[4] Goodwill is primarily related to the expected synergies, potential cost savings in operations as a result of the purchase transaction as well as potential future development of the greenfield assets. The goodwill is allocated to the Electricity segment and is deductible for tax purposes.

During the year ended December 31, 2024, the acquired portfolio of assets contributed $33.3 million to the Company Electricity revenues and $8.8 million to the Company's earnings which were included in the Company's consolidated statements of operations and comprehensive income for that period.

The following unaudited pro forma summary presents consolidated information of the Company as if the business combination had occurred on January 1, 2023. The pro forma results below include the impact of certain adjustments related to the depreciation of property, plant and equipment, amortization of intangible assets, transaction-related costs, interest costs, and the related income tax effects. This pro forma presentation does not include any impact from transaction synergies or any other material, nonrecurring adjustments directly attributable to the business combination.

	Pro forma for the Year Ended	
	2024	2023
	(Dollars in millions)	
Electricity revenues	$ 702.3	$ 702.2
Total revenues	879.7	864.9
Net income attributable to the Company's stockholders	125.2	111.0

NOTE 3 — INVENTORIES

Inventories consist of the following:

	December 31,	
	2025	2024
	(Dollars in thousands)	
Raw materials and purchased parts for assembly	$ 23,710	$ 20,575
Self-manufactured assembly parts and finished products	21,558	17,517
Total	$ 45,268	$ 38,092

NOTE 4 — COST AND ESTIMATED EARNINGS ON UNCOMPLETED CONTRACTS

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

	December 31,	
	2025	2024
	(Dollars in thousands)	
Costs and estimated earnings incurred on uncompleted contracts	$ 452,952	$ 327,671
Less billings to date	(436,100)	(321,519)
Total	$ 16,852	$ 6,152

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

	December 31,	
	2025	2024
	thousands)	
Costs and estimated earnings in excess of billings on uncompleted contracts	$ 30,011	$ 29,243
Billings in excess of costs and estimated earnings on uncompleted contracts	(13,159)	(23,091)
Total	$ 16,852	$ 6,152

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 consists of the following:

	December 31,	
	2025	2024
	(Dollars in thousands)	
Investment in Sarulla	$ 66,680	$ 69,718
Investment in Ijen	90,431	72,367
Other investments	5,000	2,500
Total investment in unconsolidated companies	$ 162,111	$ 144,585

Investment in unconsolidated businesses and equity in the earnings (losses) of investees are included under the Electricity segment.

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 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. The Company has a significant influence over the Sarulla project through representation on Sarulla's board of directors, and thus accounts for its investment in the Sarulla geothermal project under the equity method prescribed by ASC 323 - Investments - Equity Method and Joint Ventures.

During the years ended December 31, 2025, 2024 and 2023, the Company made no cash equity investment in the Sarulla complex. As of December 31, 2025, total cash investment in the Sarulla complex since its inception is $62.0 million.

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 under 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,		
	2025	2024	2023
	(Dollars in thousands)		
Change in unrealized gains or (losses) in respect of the Company's share in derivatives instruments of unconsolidated investment that qualifies as a cash flow hedge	$ (1,230)	$ 602	$ (470)

The related accumulated gain recorded by the Company under accumulated other comprehensive income as of December 31, 2025, 2024 and 2023 and was $0.9 million, $2.1 million and $1.5 million, respectively.

In the second quarter of 2022, Sarulla agreed with its banks on a framework that will enable it to perform remediation works that are aimed to restore the power plants' performance. The first phase of the recovery plan included the drilling of an additional production well, which was successful, and certain modifications to surface equipment are still underway. Following the positive indications from the first phase, during the second quarter of 2024, Sarulla commenced discussions with the banks towards implementation of the additional phases and expects to commence drilling of additional two wells, in 2026, aiming for the same target zone of the successful well drilled earlier. As the Company determined that the current situation and circumstances related to its equity method investment in Sarulla are temporary, no impairment testing was required at year-end.

The Ijen Project

On July 2, 2019, the Company acquired 49% of the Ijen geothermal project from a subsidiary of Medco Power (“Medco”), which is a 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 2025, 2024 and 2023, the Company made additional cash investments of approximately $14.9 million, $15.9 million, and $6.1 million, respectively, and $79.5 million in total. Medco retains 51% ownership in the project company, and the Company and Medco operate the power plant 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. Refer to Note 18 - Transactions with Related Entities for additional information related to the Ijen project.

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: (i) 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; (ii) the nature of the Company's involvement with the entity; (iii) whether control of the entity may be achieved through arrangements that do not involve voting equity; (iv) whether there is sufficient equity investment at risk to finance the activities of the entity; and (v) 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: (i) whether the Company has the power to direct the activities of the VIE that most significantly impact the entity's economic performance; and (ii) 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. Some 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 for each. 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, 2025 and 2024:

	December 31, 2025		December 31, 2024	
	Project Debt	PPAs	Project Debt	PPAs
	(Dollars in thousands)		(Dollars in thousands)	
Assets:				
Restricted cash and cash equivalents	$ 133,289	$ —	$ 111,248	$ —
Other current assets	149,574	37,473	134,316	43,368
Property, plant and equipment, net	2,191,754	1,268,325	1,852,498	1,418,750
Construction-in-process	243,655	148,989	85,592	165,850
Other long-term assets	410,150	48,855	286,840	89,261
Total assets	$ 3,128,422	$ 1,503,642	$ 2,470,494	$ 1,717,229
Liabilities:				
Accounts payable and accrued expenses	$ 54,526	$ 12,293	$ 28,028	$ 12,635
Long-term debt	778,422	—	710,477	—
Other long-term liabilities	483,961	139,554	427,813	72,374
Total liabilities	$ 1,316,909	$ 151,847	$ 1,166,318	$ 85,009

NOTE 7— FAIR VALUE OF FINANCIAL INSTRUMENTS

The fair value measurement guidance clarifies that fair value represents the amount that would be received upon selling an asset or paid upon transferring a liability in an orderly transaction between market participants at the measurement date. 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 observable inputs that reflect quoted prices for identical assets or liabilities in active markets;

Level 2 — inputs other than quoted prices included in Level 1 that are observable for the asset or liability either directly or indirectly;

Level 3 — unobservable inputs.

The following table sets forth certain fair value information at December 31, 2025 and 2024 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, 2025				
	Carrying Value	Fair Value			
	Total	Total	Level 1	Level 2	Level 3
	(Dollars in thousands)				
Assets:					
Current assets:					
Cash equivalents (including restricted cash accounts)	$ 47,463	$ 47,463	$ 47,463	$ —	$ —

Derivatives: cross currency swap [2]	1,343	1,343	—	1,343	—
Long-term assets:					
Derivatives: interest rate swap [3]	1,407	1,407	—	1,407	—
Derivatives: cross currency swap [2]	11,925	11,925	—	11,925	—
Liabilities:					
Current liabilities:					
Derivatives: interest rate swap [3]	(832)	(832)	—	(832)	—
Long-term liabilities:					
Derivatives: interest rate swap [3]	(430)	(430)	—	(430)	—
	$ 60,876	$ 60,876	$ 47,463	$ 13,413	$ —

	December 31, 2024				
	Carrying Value	Fair Value			
	Total	Total	Level 1	Level 2	Level 3
	(Dollars in thousands)				
Assets:					
Current assets:					
Cash equivalents (including restricted cash accounts)	$ 52,031	$ 52,031	$ 52,031	$ —	$ —
Derivatives: interest rate swap [3]	180	180	—	180	—
Derivatives: currency forward contracts [1]	550	550	—	550	—
Liabilities:					
Current liabilities:					
Derivatives: cross-currency swap [2]	(3,500)	(3,500)	—	(3,500)	—
Long-term liabilities:					
Derivatives: cross-currency swap [2]	(6,653)	(6,653)	—	(6,653)	—
	$ 42,607	$ 42,607	$ 52,031	$ (9,424)	$ —

[1] 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” on December 31, 2025 and December 31, 2024, as applicable, 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.

[2] These amounts relate to cross-currency swap contracts valued primarily based on the present value of the cross-currency swap future settlement prices for U.S. Dollar and New Israeli Shekel zero yield curves and the applicable exchange rate as of December 31, 2025 and December 31, 2024, as applicable. These amounts are included within “Prepaid expenses and other”, “Deposits and other”, “Accounts payable and accrued expenses” and “Other long-term liabilities” on December 31, 2025, and 2024, in the consolidated balance sheets. Cash collateral deposits in respect of the cross-currency swap are presented under “Receivables, others” in the consolidated balance sheet. Such deposits amounted to $0.0 million as of December 31, 2025, and $9.7 million as of December 31, 2024.

[3] This amount relates to interest rate swap contracts valued primarily based on the present value of the interest rate swap settlement prices and the future 3-month SOFR prices based on USD zero yield curve as of December 31, 2025. This amount is included within “Receivables, other”, “Deposits and other”, “Accounts payable and accrued expenses”, and “Other long-term liabilities” in the consolidated balance sheets on December 31, 2025 and December 31, 2024. There were no cash collateral deposits in respect of the interest rate swap as of December 31, 2025 and 2024.

The following table presents the amounts of gain (loss) recognized in the consolidated statements of operations and comprehensive income (loss):

Derivatives instruments	Location of recognized gain (loss)	Amount of recognized gain (loss)		
		Year Ended December 31,		
		2025	2024	2023
		(Dollars in thousands)		
Derivatives not designated as hedging instruments				
Currency forward contracts [1]	(a)	$ 4,320	$ 419	$ (2,190)
Derivatives designated as cash flow hedging instruments				
Cross-currency swap [2]	(a)	25,135	357	(6,201)
Interest rate swap [2]	(b)	67	1,504	—
Total		25,202	1,861	(6,201)

(a) Derivative and foreign currency transaction gains (losses).

(b) Interest expenses, net.

[1] The foregoing currency forward transactions were not designated as hedge transactions and were 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.

[2] The foregoing cross-currency and interest rate swap transactions were designated as a cash flow hedging instruments. The changes in the cross-currency swap fair value are initially recorded in "Other comprehensive income (loss)" and a corresponding amount is reclassified out of "Accumulated other comprehensive income (loss)" to "Derivatives and foreign currency transaction gains (losses)" to offset the remeasurement of the underlying hedged transaction which also impacts the same line item in the consolidated statements of operations and comprehensive income. The changes in the interest rate swap fair value are initially recorded in "Other comprehensive income (loss)" and a corresponding amount is reclassified out of "Accumulated other comprehensive income (loss)" to "Interest expenses, net" to offset the remeasurement of the underlying hedged transaction which also impacts the same line item 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, 2025.

The following table presents the effect of derivative instruments designated as cash flow hedges on the consolidated statements of operations and comprehensive income (loss) for the years ended December 31, 2025, 2024 and 2023:

	Year Ended December 31,		
	2025	2024	2023
	(Dollars in thousands)		
Cash flow hedges:			
Balance in Accumulated other comprehensive income (loss) beginning of period	$ 684	$ (318)	$ 3,920
Gain or (loss) recognized in Other comprehensive income (loss) [1]:			
Cross-currency swap	23,354	1,346	1,963
Interest rate swap	180	1,517	—
Amount reclassified from Other comprehensive income (loss) into earnings:			
Cross-currency swap	(25,135)	(357)	(6,201)
Interest rate swap	(67)	(1,504)	—
Balance in Other comprehensive income (loss) end of period	$ (984)	$ 684	$ (318)

[1] The amount of gain or (loss) recognized in Other comprehensive income (loss) for the years ended December 31, 2025, 2024 and 2023 is net of tax of $0.1 million, $0.3 million and $1.5 million, respectively.

The estimated net amount of existing gain (loss) that is reported in "Accumulated other comprehensive income (loss)" as of December 31, 2025 that is expected to be reclassified into earnings within the next 12 months is immaterial. The maximum length of time over which the Company is hedging its exposure to the variability in future cash flow is from the transaction commencement date through June 2031.

The fair value of the Company's long-term debt approximates its fair value, except for the following:

	Fair value Hierarchy	Fair Value		Carrying Amount (*)	
		2025	2024	2025	2024
		(Dollars in millions)		(Dollars in millions)	
Limited and non-recourse loans: fixed rate	3	$ 743.4	$ 636.5	$ 739.2	$ 657.3
Full recourse loans:					
Fixed-rate	3	804.8	920.4	808.7	940.4
Variable-rate	3	427.6	48.5	418.8	48.4
Financing liability: fixed-rate	3	223.0	223.4	216.4	220.6
Convertible senior notes	2	643.7	471.2	476.4	476.4

(*) The carrying amount value excludes the related deferred financing costs.

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, except for the fair value of the convertible senior notes for which the fair value was estimated based on a quoted bid price of the notes in an over-the-counter market on the last trading day of the reporting period. A hypothetical change in the quoted bid price of the convertible senior notes will result in a corresponding change in the estimated fair value of these notes. The carrying value of the deposits of $11.4 million, the short term revolving credit lines with banks of $80.0 million, and the commercial paper of $100.0 million, approximate their fair value. Future changes to the interest rate may have a direct impact on the fair value of the Company's financial instruments.

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,	
	2025	2024
	(Dollars in thousands)	
Land owned by the Company where the geothermal resource is located	$ 56,070	$ 51,500
Leasehold improvements	18,311	12,746
Machinery and equipment	419,231	389,252
Buildings and office equipment	157,534	145,272
Vehicles	21,078	20,159
Energy storage equipment	522,610	324,065
Solar facility equipment	95,036	97,502
Geothermal and recovered energy generation power plants, including geothermal wells and exploration and resource development costs:		
United States of America, net of cash grants	3,708,110	3,585,209
Foreign countries	959,613	919,680
Asset retirement cost	54,002	59,831
Total cost of property, plant and equipment	6,011,595	5,605,216
Less accumulated depreciation	(2,339,026)	(2,103,330)
Property, plant and equipment, net	$ 3,672,569	$ 3,501,886

Depreciation expense for the years ended December 31, 2025, 2024 and 2023 amounted to $252.0 million, $222.2 million and $186.5 million, respectively. Depreciation expense for the years ended December 31, 2025, 2024, and 2023 is net of the impact of the cash grant in the amount of $6.9 million, $6.9 million and $6.9 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 $3,852.9 million and $3,429.7 million as of December 31, 2025 and 2024, respectively. These amounts as of December 31, 2025 and 2024 are net of cash grants in the amount of $114.3 million and $121.1 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 $868.6 million and $827.8 million as of December 31, 2025 and 2024, 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 $363.4 million and $382.7 million as of December 31, 2025 and 2024, 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 97% interest in a geothermal power plant in Guatemala. The net book value of the assets related to the power plant was $26.3 million and $30.6 million at December 31, 2025 and 2024, respectively. The Company sells the electricity produced by the power plant to INDE, a Guatemalan power company under a PPA ending in 2034.

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 $38.3 million and $41.0 million at December 31, 2025 and 2024, respectively. The Company sells the electricity produced by the power plant to INDE under a long-term PPA ending in 2027, and to another local purchaser.

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. Platanares sells the electricity produced by the power plant to ENEE, the national utility of Honduras under a 30-year PPA which expires in 2047. The net book value of the assets related to the power plant was $68.6 million and $74.9 million at December 31, 2025 and 2024, respectively.

The Company, through its subsidiary, Geothermie Bouillante ("GB"), owns a power plant in Guadeloupe. The net book value of the assets related to the power plant was $158.6 million and $112.4 million at December 31, 2025 and 2024, respectively. GB sells the electricity produced by the power plant to EDF, the French electric utility, under a 15-year PPA ending in 2030.

Construction-in-Process

Construction-in-process consists of the following:

	December 31,	
	2025	2024
	(Dollars in thousands)	
Projects under exploration and development:		
Up-front bonus costs	$ 5,331	$ 5,331
Exploration and development costs	280,836	187,669
Interest capitalized	703	703
Total projects under exploration and development	286,870	193,703
Projects under construction:		
Up-front bonus costs	11,031	11,031
Drilling and construction costs	711,666	529,773
Interest capitalized	38,607	21,082
Total projects under construction	761,304	561,886
Total projects under exploration and development and construction	$ 1,048,174	$ 755,589

	Projects under exploration and development			
	Up-front Bonus Costs	Exploration and Development Costs	Interest Capitalized	Total
	(Dollars in thousands)			
Balance at December 31, 2022	$ 5,335	$ 89,230	$ 703	$ 95,268
Cost incurred during the year	—	70,667	—	70,667
Write off of unsuccessful exploration costs	—	(3,459)	—	(3,459)
Balance at December 31, 2023	5,335	156,438	703	162,476
Cost incurred during the year	—	36,339	—	36,339
Write-off of unsuccessful exploration costs	(4)	(1,967)	—	(1,971)
Transfer of projects under exploration and development to projects under construction	—	(3,141)	—	(3,141)
Balance at December 31, 2024	5,331	187,669	703	193,703
Cost incurred during the year	—	97,234	—	97,234
Transfer of projects under exploration and development to projects under construction	—	(4,067)	—	(4,067)
Balance at December 31, 2025	$ 5,331	$ 280,836	$ 703	$ 286,870

	Projects under construction			
	Up-front Bonus Costs	Drilling and Construction Costs	Interest Capitalized	Total
	(Dollars in thousands)			
Balance at December 31, 2022	$ 11,156	$ 761,129	$ 25,645	$ 797,930
Cost incurred during the year	—	473,422	15,181	488,603
Cost write-off	—	(993)	—	(993)
Transfer of completed projects to property, plant and equipment	—	(615,142)	(17,907)	(633,049)
Balance at December 31, 2023	11,156	618,416	22,919	652,491
Cost incurred during the year	—	367,674	12,212	379,886
Cost write-off	—	(1,958)	—	(1,958)
Transfer of projects under exploration and development to projects under construction	—	3,141	—	3,141
Transfer of completed projects to property, plant and equipment	(125)	(457,500)	(14,049)	(471,674)
Balance at December 31, 2024	11,031	529,773	21,082	561,886
Cost incurred during the year	—	499,590	27,765	527,355
Cost write-off	—	(1,172)	—	(1,172)
Transfer of projects under exploration and development to projects under construction	—	4,067	—	4,067
Transfer of completed projects to property, plant and equipment	—	(320,592)	(10,240)	(330,832)
Balance at December 31, 2025	$ 11,031	$ 711,666	$ 38,607	$ 761,304

Impairment of Long-lived Assets

During the year ended December 31, 2025, the Brawley power plant has been generating electricity below its generating capacity and at less than 3MW, which was lower than its capacity and Company's expectations, primarily due to the continuous wellfield issues. In the fourth quarter of 2025, as part of its resources allocation plan, the Company decided to cease all additional investments in the Brawley power plant as all previous remediation efforts have failed. As a result, the Company concluded that the Brawley power plant will no longer generate positive future cash flows and estimated the fair value of the Brawley power plant assets to be zero. As a result, the Company recorded a non-cash impairment loss of $7.2 million which was presented in the consolidated statement of operations and comprehensive income (loss) under "Impairment of long-lived-assets" for the year ended December 31, 2025. This write-off is allocated to the Electricity segment.

During the year ended December 31, 2025, the Company recorded a non-cash impairment loss of $4.9 million related to the expected termination of a waste-heat agreement between the Company's wholly-owned subsidiary, OREG2, and its customer. As a result of the expected waste-heat agreement termination, the Company concluded that the facility is no longer expected to generate positive future cash flows and estimated the related fair value of the facility to be zero. This non-cash impairment loss was presented in the consolidated statement of operations and comprehensive income (loss) under "Impairment of long-lived-assets" for the year ended December 31, 2025. This write-off is allocated to the Electricity segment.

NOTE 9 — INTANGIBLE ASSETS AND GOODWILL

As of December 31, 2025 and 2024, intangible assets amounted to $274.5 million and $301.7 million, respectively, net of accumulated amortization of $209.0 million and $177.7 million, respectively. Intangible assets are mainly related to the Company's PPAs acquired in business combination transactions, and to its energy storage activities.

The following table summarizes the information related to the Company's intangible assets as of December 31, 2025 and 2024:

	December 31, 2025		December 31, 2024	
	Gross Carrying Amount	Accumulated Amortization	Gross Carrying Amount	Accumulated Amortization
	(Dollars in thousands)		(Dollars in thousands)	
Intangible assets:				
Electricity segment	$ 429,209	$ (176,713)	$ 425,115	$ (150,108)
Energy Storage segment	54,310	(32,257)	54,310	(27,573)
Total	$ 483,519	$ (208,970)	$ 479,425	$ (177,681)
Intangible liabilities:				
Unfavorable contract liabilities	$ (20,826)	$ 3,346	$ (5,000)	$ 909

Amortization expense for the years ended December 31, 2025, 2024 and 2023 amounted to $25.4 million, $27.8 million and $26.8 million, respectively. Amortization expenses are net of the amortization of the unfavorable contract liability primarily associated with the Blue Mountain PPA as further described below.

In June 2025, the Company completed the acquisition of the Blue Mountain power plant from Cyrq Energy which resulted in an increase of $16.8 million to Other long-term liabilities relating to the long-term electricity PPA, as further described under Note 2 to the consolidated financial statements. In January 2024, the Company completed the acquisition of a portfolio of geothermal and solar assets from EGPNA which resulted in an increase of $23.6 million to intangible assets relating to long-term electricity PPAs, as further described under Note 2 to the consolidated financial statements.

As of December 2025, 2024 and 2023, the Company assessed whether there were 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 indications that the intangible assets are not recoverable in 2025, 2024 and 2023.

Estimated future amortization expense for the intangible assets and related other long-term liabilities, as of December 31, 2025 is as follows:

	(Dollars in thousands)
Year ending December 31:	
2026	$ 24,578
2027	22,365
2028	22,092
2029	22,068
2030	20,758
Thereafter	145,114
Total	$ 256,975

Goodwill

Goodwill amounting to $168.2 million and $151.0 million as of December 31, 2025 and 2024, respectively, represents the excess of the fair value of consideration 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. For the years 2025, 2024 and 2023, the Company's qualitative impairment assessment of goodwill related to its reporting units resulted in no impairment.

Changes in the carrying amount of the Company’s goodwill for the years ended December 31, 2025 and 2024 were as follows:

	2025	2024
	(Dollars in thousands)	
Goodwill as of January 1,	$ 151,023	$ 90,544

Goodwill acquired [(1)]	16,388	60,872
Translation differences	833	(393)
Goodwill as of December 31,	$ 168,244	$ 151,023

[(1)] Goodwill acquired in 2025 and 2024 is related to the Blue Mountain and Enel Purchase transactions, respectively, as further described under Note 2 to the consolidated financial statements.

NOTE 10 — ACCOUNTS PAYABLE AND ACCRUED EXPENSES

Accounts payable and accrued expenses consist of the following:

	December 31,	
	2025	2024
	(Dollars in thousands)	
Trade payable	$ 123,991	$ 124,697
Salaries and other payroll costs	31,420	30,206
Customer advances	3,053	3,613
Accrued interest	22,990	23,274
Income tax payable	11,466	8,885
Property tax payable	4,675	3,812
Scheduling and transmission	1,789	1,714
Royalty accrual	5,633	7,062
Deferred income	21,125	22,500
Warranty accrual	2,296	1,287
Other	6,318	7,284
Total	$ 234,757	$ 234,334

NOTE 11 — LONG-TERM DEBT, CREDIT AGREEMENTS AND COMMERCIAL PAPER

The Company's long-term debt consists of the following:

	December 31,	
	2025	2024
	(Dollars in thousands)	
Limited and non-recourse agreements [(*)]:		
Limited recourse:	$ 692,273	$ 603,006
Non-recourse:	46,903	54,309
Total limited and non-recourse agreements	$ 739,176	$ 657,315
Less current portion	(79,885)	(70,262)
Noncurrent portion	$ 659,291	$ 587,053
Full recourse agreements [(*)]:	$ 1,227,545	$ 988,812
Less current portion	(214,207)	(161,313)
Noncurrent portion	$ 1,013,338	$ 827,499
Convertible senior notes (all noncurrent) [(*)]	$ 476,437	$ 476,437
Financing liability	$ 216,396	$ 220,569

Less current portion	(9,749)	(4,093)
Noncurrent portion	$ 206,647	$ 216,476

(*) The amounts presented exclude the related deferred financing costs, if any.

Additional information related to the Company's long-term debt is detailed in the following table below:

Loan	Inception Date	Amount Issued	Balance as of December 31, 2025	Annual Interest Rate (1)	Maturity Date
		(Dollars in millions)			
Limited recourse loans:					
Mammoth Senior Secured Notes 2025	9/2025	$ 23.4	$ 23.4	6.95%	7/2034
Geothermie Bouillante tranche 1	8/2025	39.2	35.7	3-month EUROBOR+1.8%	12/2030
Geothermie Bouillante tranche 2	8/2025	55.7	56.3	3-month EUROBOR+2.0%	6/2046
Dominica Loan	8/2025	37.6	37.6	2.40%	9/2042
Bottleneck Loan	11/2024	72.6	68.9	6.31%	11/2039
Mammoth Senior Secured Notes	3/2024	135.1	120.4	6.73%	7/2047
Finance Agreement with DFC:					
DFC Loan - Tranche I	8/2012	85.0	23.6	6.34%	12/2030
DFC Loan - Tranche II	8/2012	180.0	47.6	6.29%	6/2030
DFC Loan - Tranche III	8/2012	45.0	13.4	6.12%	12/2030
DFC - Platanares Loan	10/2018	114.7	55.3	7.02%	9/2032
OFC 2 Senior Secured Notes:					
Series A	10/2011	151.7	48.6	4.69%	12/2032
Series C	8/2014	140.0	62.6	4.61%	12/2032
Idaho Refinancing Note	11/2022	61.6	52.4	6.26%	3/2038
U.S. Department of Energy	8/2011	96.8	24.8	2.60%	2/2035
Prudential Capital Group – Nevada	9/2013	30.7	21.7	6.75%	12/2037
Non-recourse loan:					
Don A. Campbell Senior Secured Notes	11/2016	92.5	46.9	4.03%	9/2033
Total limited and non-recourse loans:			$ 739.2		
Full recourse loans:					
Discount 2025 III Loan	12/2025	$ 100.0	$ 100.0	3-month SOFR+2.42%	11/2034
Discount 2025 II Loan	5/2025	50.0	46.9	3-month SOFR+2.4%	5/2033
Hapoalim 2025 Loan	3/2025	150.0	137.6	3-month SOFR+2.45%	3/2033
Discount 2025 Loan	3/2025	50.0	45.3	3-month SOFR+2.4%	2/2033
Mizrahi 2025 Loan	2/2025	50.0	46.9	6-month SOFR+2.35%	4/2033
Hapoalim 2024 Loan	1/2024	75.0	58.6	6.60%	1/2032
HSBC Bank 2024 Loan	1/2024	125.0	87.5	3-month SOFR+2.25%	1/2028
Discount 2024 Loan	5/2024	31.8	25.8	6.75%	5/2032
Discount 2024 II Loan	9/2024	50.0	42.2	3-month SOFR+2.35%	9/2028
Mizrahi Loan 2023	11/2023	50.0	37.5	7.15%	10/2031

Hapoalim 2023 Loan	2/2023	100.0	75.0	6.45%	2/2033
Mizrahi Bank Loan	4/2022	75.0	42.2	4.10%	4/2030
Bank Hapoalim Loan	7/2021	125.0	44.6	3.45%	6/2028
HSBC Bank Loan	7/2021	50.0	21.4	3.45%	7/2028
Discount Bank Loan	9/2021	100.0	50.0	2.90%	9/2029
Senior Unsecured Bonds - Series 4	7/2020	289.8	188.1	3.35%	6/2031
Senior Unsecured Loan:					
Migdal Loan	3/2018	100.0	62.3	4.80%	3/2029
Additional Migdal Loan	3/2019	50.0	31.1	4.60%	3/2029
Second Addendum Migdal Loan	4/2020	50.0	31.1	5.44%	3/2029
Loan Agreements with DEG:					
DEG 2 Loan	12/2016	50.0	12.5	6.28%	6/2028
DEG 3 Loan	2/2019	41.5	10.9	6.04%	6/2028
DEG 4 Loan	4/2024	30.0	30.0	7.79%	6/2031
Total full-recourse loans:			$ 1,227.5		
Total limited, non-recourse and full-recourse loans:			$ 1,966.7		

(1) unless stated otherwise.

The Company entered into the following long-term agreements during the years ended December 31, 2025 and 2024:

Full-Recourse Third-Party Debt

Discount 2025 III Loan

On December 31, 2025, the Company entered into a definitive loan agreement (the "Discount 2025 III Loan Agreement") with Discount Bank. The Discount 2025 III Loan Agreement provides for a loan by Discount Bank to the Company in an aggregate principal amount of $100.0 million (the "Discount 2025 III Loan"). The outstanding principal amount of the Discount 2025 III Loan will be repaid in 36 quarterly payments of $2.8 million each, commencing on February 22, 2026. The Discount 2025 III Loan Agreement includes various affirmative and negative covenants, including a requirement that the Company maintain (i) a net debt-to-adjusted EBITDA ratio not to exceed 6.0, (ii) a minimum equity capital amount of not less than $750 million and (iii) an equity capital to total assets ratio of not less than 25%. The Discount 2025 III Loan Agreement includes other customary affirmative and negative covenants, including payment and covenant events of default.

Discount 2025 II Loan

On May 14, 2025, the Company entered into a definitive loan agreement (the "Discount 2025 II Loan Agreement") with Discount Bank. The Discount 2025 II Loan Agreement provides for a loan by Discount Bank to the Company in an aggregate principal amount of $50.0 million (the "Discount 2025 II Loan"). The outstanding principal amount of the Discount 2025 II Loan will be repaid in 32 quarterly payments of $1.6 million each, commencing on August 22, 2025. The Discount 2025 II Loan Agreement includes various affirmative and negative covenants, including a requirement that the Company maintain (i) a net debt-to-adjusted EBITDA ratio not to exceed 6.0, (ii) a minimum equity capital amount of not less than $750 million and (iii) an equity capital to total assets ratio of not less than 25%. The Discount 2025 II Loan Agreement includes other customary affirmative and negative covenants, including payment and covenant events of default.

Hapoalim 2025 Loan

On March 31, 2025, the Company entered into a definitive loan agreement (the "Hapoalim Loan Agreement 2025") with Bank Hapoalim B.M. The Hapoalim Loan Agreement 2025 provides for a loan by Bank Hapoalim B.M. to the Company in an aggregate principal amount of $100.0 million (the "Hapoalim 2025 Loan"). On June 30, 2025, the Company amended and restated the Hapoalim Loan Agreement 2025 in order to increase the original principal amount of the Hapoalim 2025 Loan by an additional aggregated principal amount of $50 million (the "Amended Hapoalim 2025 Loan"). The outstanding principal amount of the Amended Hapoalim 2025 Loan will be repaid in 31 quarterly payments of $4.74 million each, commencing on September 30, 2025. The Amended Hapoalim 2025 Loan agreement includes various

affirmative and negative covenants, including a requirement that the Company maintain (i) a net debt to adjusted EBITDA ratio not to exceed 6.0, (ii) a minimum equity capital amount of not less than $750 million and (iii) an equity capital to total assets ratio of not less than 25%. The amended Hapoalim 2025 Loan agreement includes other customary affirmative and negative covenants, including payment and covenant events of default.

Discount 2025 Loan

On March 27, 2025, the Company entered into a definitive loan agreement (the "Discount Loan Agreement 2025") with Discount Bank. The Discount Loan Agreement 2025 provides for a loan by Discount Bank to the Company in an aggregate principal amount of $50.0 million (the "Discount 2025 Loan"). The outstanding principal amount of the Discount 2025 Loan will be repaid in 32 quarterly payments of 1.6 million each, commencing on May 22, 2025. The Discount Loan Agreement 2025 includes various affirmative and negative covenants, including a requirement that the Company maintain (i) a net debt to adjusted EBITDA ratio not to exceed 6.0, (ii) a minimum equity capital amount of not less than $750 million, and (iii) an equity capital to total assets ratio of not less than 25%. The Discount Loan Agreement 2025 includes other customary affirmative and negative covenants, including payment and covenant events of default.

Mizrahi 2025 Loan

On February 2, 2025, the Company entered into a definitive loan agreement (the "Mizrahi Loan Agreement 2025") with Mizrahi Bank. The Mizrahi Loan Agreement 2025 provides for a loan by Mizrahi Bank to the Company in an aggregate principal amount of $50.0 million (the "Mizrahi 2025 Loan"). The outstanding principal amount of the Mizrahi 2025 Loan will be repaid in 16 semi-annual payments of 3.1 million each, commencing on October 15, 2025. The Mizrahi Loan Agreement 2025 includes various affirmative and negative covenants, including a requirement that the Company maintain (i) a net debt to adjusted EBITDA ratio not to exceed 6.0, (ii) a minimum equity capital amount of not less than $750 million, and (iii) an equity capital to total assets ratio of not less than 25%. The Mizrahi Loan Agreement 2025 includes other customary affirmative and negative covenants, including payment and covenant events of default.

Hapoalim 2024 Loan

Concurrently with the purchase transaction with EGPNA, on January 2, 2024, as further described under Note 2, the Company entered into a definitive loan agreement (the "BHI Loan Agreement 2024") with Hapoalim Bank. The BHI Loan Agreement 2024 provides for a loan by Hapoalim Bank to the Company in an aggregate principal amount of $75 million (the "Hapoalim 2024 Loan"). The BHI Loan Agreement 2024 includes various affirmative and negative covenants, including a requirement that the Company maintain (i) a financial debt to adjusted EBITDA ratio not to exceed 6.0, (ii) a minimum equity capital amount of not less than $75 million, and (iii) an equity capital to total assets ratio of not less than 25%. The BHI Loan Agreement includes other customary affirmative and negative covenants, including nonpayment and noncompliance events of default.

HSBC Bank 2024 Loan

Concurrently with the purchase transaction with EGPNA, on January 2, 2024, as further described under Note 2, the Company entered into a definitive loan agreement (the "HSBC Loan Agreement 2024") with HSBC Bank. The HSBC Loan Agreement 2024 provides for a loan by HSBC Bank to the Company in an aggregate principal amount of $125 million (the "HSBC Bank 2024 Loan"). The outstanding principal amount of the HSBC Bank 2024 Loan will be repaid in 7 semi-annual payments of $12.5 million each, commencing on July 1, 2024, and an additional final principal payment on January 1, 2028 of $37.5 million. The duration of the HSBC Bank 2024 Loan is 4 years and it payable quarterly. The HSBC Loan Agreement 2024 includes various affirmative and negative covenants, including a requirement that the Company maintain (i) a financial debt to adjusted EBITDA ratio not to exceed 6.0, (ii) a minimum equity capital amount of not less than $750 million, and (iii) an equity capital to total assets ratio of not less than 25%. The HSBC Loan Agreement 2024 includes other customary affirmative and negative covenants, including nonpayment and noncompliance events of default.

Interest Rate Swap

Concurrently with the issuance of the HSBC Bank 2024 Loan, the Company entered into a long-term interest rate swap ("IR Swap") transaction with the objective of hedging the variable interest rate fluctuations related to the HSBC Bank 2024 Loan at a fixed 3-month SOFR of 3.9%. The terms of the IR Swap match those of the HSBC Bank 2024 Loan, including the notional amount of the principal and interest payment dates. The Company designated the IR Swap as a cash flow hedge as per ASC 815, Derivatives and Hedging, and accordingly measures the IR Swap instrument at fair value. The changes in the IR Swap fair value are initially recorded in Other Comprehensive Income (Loss) and reclassified to Interest expense, net in the same period or periods during which the hedged transaction affects earnings. The hedged transaction and the IR Swap effect in earnings are presented in the same line item in the consolidated statements of operations and comprehensive income.

Discount 2024 Loan

On May 22, 2024, the Company entered into a definitive loan agreement (the "Discount 2024 Loan Agreement") with Israel Discount Bank Ltd. (“Discount Bank”). The Discount 2024 Loan Agreement provides for a loan by Discount Bank to the Company in an aggregate principal amount of $31.8 million (the “Discount 2024 Loan”). The outstanding principal amount of the Discount 2024 Loan will be repaid in 32 quarterly payments of $1 million each, commencing on August 22, 2024. The Discount 2024 Loan Agreement includes various affirmative and negative covenants, including a requirement that the Company maintain (i) a financial debt to adjusted EBITDA ratio not to exceed 6.0, (ii) a minimum equity capital amount of not less than $750 million, and (iii) an equity capital to total assets ratio of not less than 25%. The Discount 2024 Loan Agreement includes other customary affirmative and negative covenants, including payment and covenant events of default.

Discount 2024 II Loan

On September 26, 2024, the Company entered into a definitive loan agreement (the "Discount 2024 II Loan Agreement") with Discount Bank of New York (“Discount NY Bank”). The Discount 2024 II Loan Agreement provides for a loan by Discount NY Bank to the Company in an aggregate principal amount of $50 million (the “Discount 2024 II Loan”). The outstanding principal amount of the Discount 2024 II Loan will be repaid in 15 quarterly payments of $1.56 million each, commencing on December 31, 2024, with a final 16th payment equal to the remaining unpaid principal amount of the loan of $26.6 million. The duration of the Discount 2024 II Loan is 4 years, unless extended by the Company under certain conditions for an additional period of up to 4 years. The Discount 2024 II Loan bears an annual interest of 3-month Term SOFR plus 2.35%, with a SOFR floor of 2.5%. The Discount 2024 II Loan Agreement includes various affirmative and negative covenants, including a requirement that the Company maintain (i) a financial debt to adjusted EBITDA ratio not to exceed 6.0, (ii) a minimum equity capital amount of not less than $750 million, and (iii) an equity capital to total assets ratio of not less than 25%. The Discount 2024 II Loan Agreement includes other customary affirmative and negative covenants, including payment and covenant events of default.

The Senior Unsecured Bonds - Series 4 and Related Cross-Currency Swap

Senior Unsecured Bonds - Series 4

On July 1, 2020, the Company concluded an auction tender and accepted subscriptions for New Israeli Shekels ("NIS") 1.0 billion aggregate principal amount of senior unsecured bonds (the “Senior Unsecured Bonds - Series 4”). The Senior Unsecured Bonds - Series 4 are denominated in NIS and were converted to approximately $289.8 million using a cross-currency swap transaction shortly after the completion of such issuance as further detailed below. The Senior Unsecured Bonds - Series 4 are payable semi-annually in arrears starting December 2020 and will be repaid in 10 equal annual payments commencing June 2022 unless prepaid earlier by the Company pursuant to the terms and conditions of the trust instrument that governs the Senior Unsecured Bonds - Series 4.

Cross-Currency Swap

Concurrently with the issuance of the Senior Unsecured Bonds - Series 4, the Company entered into a long-term cross-currency swap with the objective of hedging the currency rate fluctuations related to the aggregated principal amount and interest of the Senior Unsecured Bonds - Series 4 at an average fixed rate of 4.34%. The terms of the cross-currency swap match those of the Senior Unsecured Bonds - Series 4, including the notional amount of the principal and interest payment dates. The Company designated the cross-currency swap as a cash flow hedge as per ASC 815, Derivatives and Hedging and accordingly measures the cross-currency swap instrument at fair value. The changes in the cross-currency swap fair value are initially recorded in Other Comprehensive Income (Loss) and reclassified to Derivatives and foreign currency transaction gains (losses) in the same period or periods during which the hedged transaction affects earnings. The hedged

transaction and the Senior Unsecured Bonds - Series 4 effect in earnings are presented in the same line item in the consolidated statements of operations and comprehensive income.

Non-Recourse and Limited-Recourse Third-Party Debt

Mammoth Senior Secured Notes 2025 - Limited-Recourse

On September 18, 2025, a wholly-owned indirect subsidiary of the Company (the "Issuer"), entered into a note purchase agreement with certain noteholders under the management of Prudential Investment Management, Inc., pursuant to which the Issuer issued $23.4 million principal amount of senior secured notes (the "Mammoth Senior Secured Notes 2025" or "MSSN 2025"). The note purchase agreement also includes a $3.0 million tranche of floating rate notes to be issued in the event of a shortfall in debt service with respect to the MSSN 2025. The Issuer shall pay a commitment fee on the revolving note tranche at a rate of 0.75% per annum. If drawn, the revolving notes shall bear interest at a rate equal to Term SOFR+2.50%. The MSSN 2025 are secured by the equity interests in the Issuer, and by the Issuer's 100% ownership interests in a wholly-owned holding subsidiary that owns project subsidiaries including four geothermal power plants known as the Mammoth G1, G2, G3 and Casa Diablo 4 ("CD4") projects. The MSSN 2025 will be repaid in 15 semi-annual payments, commencing on July 7, 2027. The Company provided a limited guarantee with respect to certain obligations of the Issuer as a member of CD4 which was amended and restated to accommodate the Mammoth Senior Secured Notes 2025.

The MSSN 2025 contains various customary restrictive covenants under the MSSN 2025, including limitations on additional indebtedness of the Issuer and its subsidiaries. Failure to comply with these and other covenants will, subject to customary cure rights, constitute an event of default by the Issuer. In addition, there are restrictions on the ability of the Issuer to make distributions to its shareholders. Among other things, the distribution restrictions include both a historical and projected minimum debt service coverage ratio requirement.

Geothermie Bouillante Loan - Limited-Recourse

On July 31, 2025, Geothermie Bouillante S.A. ("GB"), a subsidiary of the Company that owns and operates the geothermal power plant in Guadeloupe, in which the Company indirectly holds a 63.75% ownership interest, entered into loan agreements (the "GB Loan Agreements") with a consortium of French banks, pursuant to which GB will borrow up to €99.8 million aggregate principal amount, in connection with GB's geothermal project in Guadeloupe.

The loan (the "GB Loan") is comprised of two tranches. One tranche of €33.5 million was drawn on August 14, 2025 to cover the refinancing of investment in the existing power plant. It bears interest of 3-month Euro Interbank Offered Rate ("EUROBOR") plus 1.8%, and matures in 5 years. The base rate as of August 14, 2025 was 2.14%. The second tranche covers the construction of GB's 10MW expansion project which is expected to be commissioned in 2026, bears interest of 3-month EUROBOR plus 2.0%, and matures in 21 years. The base rate as of August 14, 2025 was 2.68%. €42.5 million of the second tranche was drawn on August 18, 2025 and €5.2 million during the fourth quarter of 2025. The remainder of the GB Loan withdrawals are expected to occur during the first half of 2026. The proceeds from the GB Loan were partially used to fully prepay the limited recourse Société Générale and Bpifrance loans which had an immaterial aggregated principal balance of $2.4 million.

The GB Loan is secured by all of the assets of GB and by the ownership interests in GB. The GB Loan Agreements require GB to comply with certain covenants, including, among others, restrictions on the incurrence of indebtedness or liens, amendment or modification of material project documents, or the ability of GB to merge or consolidate with another entity. In addition, there are restrictions on the ability of GB to make distributions to its shareholders, which include a required historical and projected debt service cover ratio. The drawdowns are subject to typical conditions for draws, including, among others, verification of project costs, and compliance with certain gearing ratios.

GB Loan Interest Rate Swap

Concurrently with the issuance of the GB Loan, the Company entered into a long-term interest rate swap (the "IR Swap") transaction with the objective of hedging the variable interest rate fluctuations related to the GB Loan. The first tranche was hedged at a fixed 3-month EUROBOR of 2.29%, and the second tranche was hedged at a 3-month EUROBOR of 2.83%. The Company designated the IR Swap as a cash flow hedge as per ASC 815, Derivatives and Hedging, and accordingly measures the IR Swap instrument at fair value. The changes in the IR Swap fair value are initially recorded in Other Comprehensive Income (Loss) and reclassified to Interest Expense, Net in the same period or periods during which the hedged transaction affects earnings. The hedged transaction and the IR Swap effect in earnings are presented in the same line item in the consolidated statement of operations and comprehensive income.

Dominica Loan - Limited-Recourse

On June 23, 2025, one of the Company's subsidiaries, Geothermal Power Company of Dominica ("GPCD"), entered into loan agreements (the "Dominica Loan Agreements") with the Caribbean Development Bank ("CDB") and Caricom Development Fund ("CDF"), (collectively, the "Lenders") pursuant to which GPCD will borrow up to $49.8 million aggregate principal amount at an average interest rate of 2.4% (the "Dominica Loan") in connection with GPCD's 10MW Geothermal Project in Dominica.

On August 13, 2025, an aggregate principal amount of $37.6 million was drawn under the Dominica Loan, and the remainder is expected to be drawn during the remaining construction period. The proceeds are used to refinance the development and construction of the power plant, which were initially financed using equity.

The Dominica Loan is secured by all of the assets of GPCD. The GPCD Loan Agreements require GPCD to comply with certain covenants, including, among others, restrictions on the incurrence of indebtedness or liens, amendment or modification of material project documents, or the ability of GPCD to merge or consolidate with another entity. In addition, there are restrictions on the ability of GPCD to make distributions to its shareholders after the commercial operation of the power plant, which include a required historical and projected DSCR.

Bottleneck Loan

On November 19, 2024, a wholly owned indirect subsidiary of the Company entered into a note purchase agreement ("NPA") for the private placement of $72.6 million senior secured notes due November 29, 2039. The NPA was signed with various investors, including funds and accounts managed by BlackRock Investment Management, LLC. and affiliates thereof ("BlackRock") for the financing of the Bottleneck battery energy storage project located in the Central Valley of California (the "Project").

On November 20, 2024, the Company completed the drawdown of the full loan amount (the "Bottleneck Loan"), bearing an annual interest rate of 6.31%. The loan will be repaid in 30 semi-annual repayments based on a sculpted amortization schedule starting on May 29, 2025. The NPA contains customary terms and conditions for senior secured notes issued in a private placement, including, without limitation, affirmative and negative covenants such as information reporting, minimum debt service coverage ratios, and prohibitions on certain fundamental changes of the borrower. The NPA also contains customary events of default with customary cure and notice periods, including, without limitation, nonpayment, breach of covenant, and certain events of bankruptcy. The Company provided a guaranty to the note holders covering certain outstanding obligations towards vendors of equipment installed in the project. Covenants will be first calculated on the date of the first principal payment in the second quarter of 2025.

Mammoth Senior Secured Notes

On March 28, 2024, Mammoth Pacific, LLC (the "Issuer"), a wholly-owned indirect subsidiary of the Company, entered into a note purchase agreement with the Prudential Insurance Company of America, pursuant to which the Issuer issued $135.1 million principal amount of senior secured notes (the "Mammoth Senior Secured Notes"). The note purchase agreement also includes an approximately $9 million tranche of floating rate notes to be issued in the event of a shortfall in debt service with respect to the Mammoth Senior Secured Notes. The Issuer shall pay a commitment fee on the revolving note tranche at a rate of 0.5% per annum. If drawn, the revolving notes shall bear interest at a rate equal to Term SOFR plus 1.25%. The Mammoth Senior Secured Notes are secured by the equity interests in the Issuer, and by the Issuer's 100% ownership interests in its project subsidiaries including four geothermal power plants known as the Mammoth G1, G2, G3 and Casa Diablo 4 ("CD4") projects. The remaining classes of ownership interests in CD4 are owned by an unrelated third-party and are not part of the collateral security package for the Mammoth Senior Secured Notes. The Mammoth Senior Secured Notes will be repaid in 46 semi-annual payments, commencing on November 30, 2024. The Mammoth Senior Secured Notes bear interest at a fixed rate of 6.73% per annum and have a final maturity date of July 14, 2047. The Company has provided a limited guarantee with respect to certain obligations of the Issuer as a member of CD4.

There are various restrictive covenants under the Mammoth Senior Secured Notes, including limitations on additional indebtedness of the Issuer and its subsidiaries. Failure to comply with these and other covenants will, subject to customary cure rights, constitute an event of default by the Issuer. In addition, there are restrictions on the ability of the Issuer to make distributions to its shareholders. Among other things, the distribution restrictions include both a historical and projected minimum debt service coverage ratio requirement. As part of the security package, the note purchase agreement states the Issuer shall establish and maintain customary reserve accounts which include a debt service reserve account, a make-up well reserve account and a maintenance reserve account.

Other Long-term debt

Convertible Senior Notes

On June 22, 2022, the Company issued $375.0 million aggregate principal amount of its 2.5% convertible senior notes (the "Notes", or the "Original Notes") due 2027. Additionally, on July 15, 2024, the Company issued an additional 2.5% convertible senior notes (the "Additional Notes") as further described below. The Original Notes were offered and sold in a private offering to qualified institutional buyers pursuant to Rule 144A under the Securities Act of 1933, as amended, pursuant to an indenture between the Company and U.S. Bank National Association, as trustee. Additionally, the Company granted the initial purchasers an option to purchase up to an additional $56.25 million aggregate principal amount of the Notes. The initial purchasers executed their option on June 27, 2022, and by that, increased the total aggregated principal amount of the Notes issued to $431.25 million. The Notes bear annual interest of 2.5%, payable semiannually in arrears on January 15 and July 15 of each year, beginning on January 15, 2023. The Notes mature on July 15, 2027, unless earlier converted, redeemed or repurchased and are the Company's senior unsecured obligations.

Holders of the Notes may convert all or any portion of their Notes at their option at any time prior to the close of business on the business day immediately preceding January 15, 2027 only under the following circumstances: (1) during any calendar quarter commencing after the calendar quarter ending on September 30, 2022 (and only during such calendar quarter), if the last reported sale price of the Company's common stock, par value $0.001 per share (the "Common Stock"), for at least 20 trading days (whether or not consecutive) during a period of 30 consecutive trading days ending on, and including, the last trading day of the immediately preceding calendar quarter is greater than or equal to 130% of the conversion price on each applicable trading day (equivalent to an initial conversion price of approximately $90.27 per share of common stock); (2) during the five consecutive business day period immediately after any five consecutive trading day period (the "Measurement Period") in which the trading price per $1,000 principal amount of Notes, as determined following a request by a holder or holders of the Notes for each trading day of the Measurement Period was less than 98% of the product of the last reported sale price of the Company's Common Stock and the conversion rate on each such trading day; (3) if the Company calls any or all of the Notes for redemption (the Company may not redeem the notes prior to July 21, 2025), at any time prior to the close of business on the second scheduled trading day prior to the redemption date, but only with respect to the Notes called (or deemed called) for redemption; or (4) upon the occurrence of specified corporate events. On or after January 15, 2027 until the close of business on the second scheduled trading day immediately preceding the maturity date, holders may convert all or any portion of their Notes at any time, regardless of the foregoing circumstances. Upon conversion, the Company will pay cash up to the aggregate principal amount of the Notes to be converted and pay or deliver, as the case may be, cash, shares of its common stock or a combination of cash and shares of its common stock, at its election, in respect of the remainder, if any, of its conversion obligation in excess of the aggregate principal amount of the Notes being converted.

The initial conversion rate was 11.0776 shares of common stock per $1,000 principal amount of Notes, which is equivalent to an initial conversion price of approximately $90.27 per share of common stock, subject to adjustment in certain events. In addition, following certain corporate events that occur prior to the maturity date or if the Company delivers a notice of redemption, it will, in certain circumstances, increase the conversion rate for a holder who elects to convert its Notes in connection with such a corporate event or notice of redemption, as the case may be. The Company may not redeem the notes prior to July 21, 2025. The Company may redeem for cash all or any portion of the Notes, at its option, on or after July 21, 2025 and on or before the 41st scheduled trading day immediately preceding the maturity date, if the last reported sale price of its common stock has been at least 130% of the conversion price then in effect for at least 20 trading days (whether or not consecutive) during any 30 consecutive trading day period (including the last trading day of such period) ending on, and including, the trading day immediately preceding the date on which we provide notice of redemption at a redemption price equal to 100% of the principal amount of the notes to be redeemed, plus accrued and unpaid interest, but excluding the redemption date. No sinking fund is provided for the Notes. Additionally, if the Company undergoes a fundamental change (other than certain exempted fundamental changes), holders may require the Company to repurchase for cash all or any portion of their Notes at a fundamental change repurchase price equal to 100% of the principal amount of the Notes to be repurchased, plus accrued and unpaid interest.

The Company incurred approximately $11.6 million of costs in respect of the issuance of the Notes, which were deferred and are presented as a reduction to the Notes principal amounts on the consolidated balance sheets. The deferred issuance costs are amortized over the term of the Notes into interest expenses, net in the consolidated statements of operations and comprehensive income. During the years ended December 31, 2025, 2024 and 2023, $2.7 million, $2.5 million, and $2.3 million, respectively, were recorded as amortized issuance costs under interest expenses, net. The effective interest rate on the Notes, including the impact of the deferred debt issuance costs, is 3.1%. During the years ended December 31, 2025, 2024 and 2023, $11.9 million, $11.4 million, and $10.7 million, respectively, were recorded as interest expenses on these Notes.

Additionally, in connection with the issuance of the Notes as described above, on June 27, 2022, the Company used approximately $221.9 million of the net proceeds from the issuance of these Notes to prepay its Series 3 Bonds that were set to mature in September 2022 in a single bullet payment.

Capped Call Transactions

In connection with the issuance of the Original Notes described above, the Company entered into capped call transactions (the "Capped Calls") with certain counterparties. The capped call transactions will cover, subject to customary adjustments, the number of shares of our common stock initially underlying the Notes of approximately 4.8 million shares of common stock and at an initial strike price of $90.27 per share. The Capped Calls are generally intended to reduce the potential dilution to the Company's Common Stock upon any conversion of the Notes and/or offset any cash payments the Company is required to make in excess of the principal amount of converted Notes, in the event that at the time of conversion, the Common Stock price exceeds the conversion price. If, however, the market price per share of Common Stock exceeds the cap price of the Capped Calls, there would nevertheless be dilution or there would not be an offset of such potential cash payments, in each case, to the extent that such market price exceeds the cap price of the Capped Calls.

The Capped Calls exercise price is equal to the $90.27 initial conversion price of each of the Notes and the cap price of the Capped Calls is initially $107.63 per share, which represents a premium of approximately 55% above the closing price of the Company's common stock on the date of the Notes offering and is subject to customary anti-dilution adjustments. The Capped Calls transactions are separate transactions entered into by the Company with the option counterparties, are not part of the terms of the Notes and will not change the holders' rights under the Notes.

The Company paid approximately $24.5 million for the Capped Calls which was recorded as a reduction to Additional Paid-in Capital in the consolidated statements of equity in the second quarter of 2022, as such transactions qualify for the equity classification with no subsequent adjustment to fair value under ASU 815, Derivatives and Hedging. The Capped Calls are not included in the calculation of diluted earnings per share because their impact is anti-dilutive. The Capped Calls transaction does not cover the Additional Notes described below.

Additional 2.50% Senior Convertible Notes

On July 15, 2024, the Company issued an additional $45.2 million aggregate principal amount of its 2.50% Convertible Senior Notes due 2027 (the "Additional Notes"). The Additional Notes were issued as additional notes pursuant to the indenture, dated June 27, 2022, as supplemented by the first supplemental indenture, dated July 15, 2024, between the Company and U.S. Bank Trust Company, National Association, as trustee (the "Indenture"). The Additional Notes constitute a further issuance of, and form a single series with, the $431.3 million aggregate principal amount of the Company's outstanding 2.5% Convertible Senior Notes due 2027 originally issued in June 2022 (the "Original Convertible Notes" and together with the Additional Notes, the "Notes"). The Additional Notes will have substantially identical terms to the Existing Convertible Notes, except that the Additional Notes have a different issuance date and will initially trade under a different restricted CUSIP number than the Existing Convertible Notes until such time as the Additional Notes are no longer required to bear restrictive legends under the Indenture and have an unrestricted CUSIP. The aggregated proceeds received from the issuance of the Additional Notes were $44.0 million, net of discount and fees of $1.1 million.

Financing Liability

The financing liability was assumed by the Company as part of the purchase transaction with TG Geothermal Portfolio, LLC in July 2021, under which it acquired a number of geothermal assets and a transmission line. The financing liability is related to a sale and leaseback transaction entered into by TG Geothermal Portfolio, LLC in September 2015 under which it sold and leased back the undivided interests in the Dixie Valley power plant asset through June 2038. The lease transaction was accounted for by the TG Geothermal Portfolio, LLC as a finance lease due to the its continued involvement and management of the power plant and the existence of an early buy-out option in September 2024. During the fourth quarter of 2023, the Company decided to defer the buy-out payment to June 2038, as permitted under the lease transaction agreement, which resulted in an adjustment to the effective interest rate of the financing liability which increased from 2.55% to 6.12%, prospectively, and is being re-evaluated every quarter. The annual interest rate of the financing liability as of December 31, 2025, was 6.01%.

Loan	Balance as of December 31, 2025 (Dollars in millions)	Annual Interest Rate [1]	Maturity Date [2]
Financing Liability - Dixie Valley	$216.4	6.01%	June 2038

[1] payable semi-annually

[2] final maturity date of the financing liability is assuming execution of the buy-out option in June 2038.

Short-Term Commercial Paper

On October 19, 2023, the Company entered into a framework agreement for participation in the issuance of commercial paper (the "Commercial Paper Agreement") with Barak 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 Commercial Paper Agreement. On October 23, 2023, the Company completed the issuance of the Commercial Paper in the aggregate amount of $73.2 million, and subsequently on December 11, 2023, the Company issued an additional amount of $26.8 million, under the same terms. The Commercial Paper was issued for a period of 90 days and extends automatically for additional 90 days 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 Commercial Paper Agreement. The Commercial Paper bears an annual interest of three months SOFR +1.1% which will be paid at the end of each ninety days period. As of December 31, 2025, the base rate was 5.0%.

Revolving Credit Lines with Commercial Banks

As of December 31, 2025, the Company has credit agreements for committed and uncommitted credit lines with a number of financial institutions for an aggregate amount of $688.0 million (including $100.0 million from MUFG Union Bank, N.A. (“Union Bank”) and $35.0 million from HSBC Bank USA N.A. 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 $533.0 million; and (ii) the issuance of one or more letters of credit in the amount of up to $155.0 million. The credit agreements mature between March 2025 and December 2025. Loans and draws under the credit agreements or under any letters of credit will bear interest at the respective bank’s cost of funds or SOFR plus a margin. As of December 31, 2025, $80.0 million of short-term credit lines were outstanding, and letters of credit with an aggregate amount of $286.0 million were issued and outstanding under committed and non-committed lines under such credit agreements (including the amounts outstanding under the section Credit Agreements below with MUFG Union bank and HSBC bank).

Credit Agreements

Credit Agreement with MUFG Union Bank

Ormat Nevada has a credit agreement with MUFG Union Bank under which it has an aggregate available credit of up to $100.0 million as of December 31, 2025. The credit termination date is June 30, 2026.

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. As of December 31, 2025, letters of credit in the aggregate amount of $80.0 million were issued and outstanding under this credit agreement.

Credit Agreement with HSBC Bank USA N.A.

Ormat Nevada has 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, 2026. On December 31, 2025, the aggregate amount available under the credit agreement was $35.0 million. This credit line is limited to the issuance, extension, modification or amendment of letters of credit. In addition, Ormat Nevada has an uncommitted discretionary demand line of credit in the aggregate amount of $65.0 million available for letters of credit including up to $40 million of credit. 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. As of December 31, 2025, letters of credit

in the aggregate amount of $33.7 million were issued and outstanding under the committed portion of this credit agreement and $21.6 million under the uncommitted portion of the agreement.

Surety Bonds

The Company entered into surety bond agreements (the "Surety Agreements") with Chubb Limited, Travelers, Arch, Allianz and certain other third parties (the "Surety") pursuant to which, as of December 31, 2025, the Company may request that the Surety issue up to an aggregate amount of $960.0 million of surety bonds with respect to the contractual obligations of the Company and its subsidiaries, all of which were available for surety bonds and surety-backed letters of credit. There is no expiration date for the Surety Agreements, but they may be terminated by the Company at any time upon between twenty and thirty days' prior written notice to the Surety. 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, 2025, the Surety issued surety bonds in the amount of $315.7 million, and surety-backed letters of credit in the amount of $127.7 million, under the Surety Agreements.

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, including the credit agreements with MUFG Union Bank and with HSBC Bank USA N.A., the Company has agreed to maintain certain financial ratios, which are measured quarterly, such as: (i) equity of at least $750 million and in no event less than 25% of total assets; and (ii) 12-month debt, net of cash, cash equivalents marketable securities and short-term bank deposits to Adjusted EBITDA ratio not to exceed 6.0. As of December 31, 2025: (i) total equity was $2,680.9 million and the actual equity to total assets ratio was 42.9%, and (ii) the 12-month debt, net of cash, cash equivalents marketable securities and short-term bank deposits to Adjusted EBITDA ratio was 4.36 and as such, the covenants have been met as of December 31, 2025. During the year ended December 31, 2025, the Company distributed dividends in an aggregate amount of $29.1 million.

We are currently in compliance with our covenants with respect to the credit agreements, the loan agreements and the trust instrument (except as described below), 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.

As of December 31, 2025, we did not meet the dividend distribution criteria related to the DAC 1 Senior Secured Notes, which resulted in certain equity distribution restrictions from this related subsidiary. As of December 31, 2025, the amount restricted for distribution by this subsidiary was $1.0 million. There were no restrictions on the retained earnings or net income of Ormat Technologies, Inc., as the parent company, in respect of these matters, as of December 31, 2025.

Future Minimum Payments

Future minimum payments under long-term obligations, including long-term debt and financing liability, as of December 31, 2025 are as follows:

	(Dollars in thousands)
Year ending December 31:	
2026	$ 303,653
2027	780,897
2028	335,092
2029	313,212
2030	211,681
Thereafter	716,034
Total	$ 2,660,570

NOTE 12 —TAX MONETIZATION TRANSACTIONS

Heber 1 and 2 Tax Monetization Transaction

On July 10, 2025, one of the Company's wholly-owned subsidiaries that indirectly owns the Heber 1 and Heber 2 geothermal power plants entered into a partnership agreement with a private investor. Under the terms of the partnership agreement, the private investor acquired membership interests in the two Heber Geothermal power plants for an initial purchase price of $77.1 million and for which it will pay additional installments that are expected to amount to $25.7 million. The Company continues to operate and maintain the power plants and will receive substantially all the distributable cash flow generated by the power plants, as described below.

Under the terms of the partnership agreement, prior to December 31, 2032 (the "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 95% of the distributable cash and 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 75% of the distributable cash generated by the power plants and 99% of the tax attributes as long as the power plants are generating PTCs.

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 power plants again.

Private investor's capital contribution of $77.1 million was recorded as allocation to noncontrolling interests of $8.1 million, and to liability associated with sale of tax benefits of $69.0 million.

Hybrid Tax Equity Partnership

On May 20, 2025, the Company entered into a partnership agreement with a private investor under which the private investor acquired indirect membership interests in the Lower Rio and Arrowleaf storage facilities (the "Project Facilities") for total estimated consideration of $62.9 million, all of which was paid in 2025. Following the transaction, the Company continues to operate and maintain the Project Facilities.

Under the transaction agreements, prior to reaching the flip date, which was defined as the later of the date on which the private investor reaches its target return, and the end of the ITCs recapture period (the "Flip Date"), the private investor receives substantially all of the distributable cash flow generated by the Project Facilities, and substantially all of the tax attributes of the Project Facilities. Following the Flip Date, the Company will receive substantially all of the distributable cash and taxable income, on a go-forward basis.

Following the Flip Date, but no later than May 19, 2033, the Company has the option to purchase the private investor's interests at the greater of (i) the fair market value of the post-flip residual interest, (ii) five percent of the aggregate capital contributions of the private investor, (iii) the fair market value of the Class A units and (iv) the private investor's book value investment. If the Company exercises this purchase option, it will become the sole owner of the storage facilities again.

As further described below under the caption "Transferable Production and Investment Tax Credits", the Company accounts for ITCs under ASC 740 through the "Income tax (provision) benefit" line in the consolidated statements of operations and comprehensive income, and therefore, income associated with ITCs was included in the "Income tax (provision) benefit" line. Income associated with other tax attributes, was included under "Income attributable to the sale of tax benefits" line in the consolidated statement of operations and comprehensive income. The private investor's contribution of $62.9 million was primarily related to ITC benefits, and thus recorded against the related deferred tax asset, net of the amount related to noncontrolling interest of $3.9 million. Contributions related to other tax attributes are recorded to the liability associated with sales of tax benefits on the condensed consolidated balance sheets.

North Valley Tax Monetization Transaction

On October 27, 2023, one of the Company's wholly-owned subsidiaries that indirectly owns the North Valley Geothermal power plant entered into a partnership agreement with a private investor. Under the transaction documents, the private investor acquired membership interests in the North Valley Geothermal power plant project for an initial purchase price of $43.1 million and for which it will pay additional installments that are expected to amount to approximately

$6.1 million. The Company continues 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, 2032 (“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 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 Production Tax Credits ("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.

Private investor’s capital contribution of $43.1 million was recorded as allocation to noncontrolling interests of $0.3 million, and to liability associated with sale of tax benefits of $42.8 million.

Casa Diablo IV ("CD4") Tax Monetization Transaction

On December 23, 2022, one of the Company’s wholly-owned subsidiaries that indirectly owns the CD4 geothermal power plant entered into a partnership agreement with JPM. Under the transaction documents, the private investor acquired membership interests in the CD4 geothermal power plant project for an initial purchase price of $50.3 million and for which it will pay additional installments that are expected to amount to approximately $7.3 million. The Company continues 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, 2031 (“CD4 Target Flip Date”), the Company receives substantially all of the distributable cash flow generated by the project, while the private investor receives substantially 99% of the tax attributes of the project. Following the later of the CD4 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 and 95.0% of the taxable income, on a go forward basis. In the event that JPM will not reach its target return by the CD4 Target Flip Date, then for the period between the CD4 Target Flip Date and the date on which the private investor reaches its target return, JPM will receive 75% 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 has the option to purchase the private investor’s interests at the then-current fair market value, plus an amount that causes JPM to reach its target return, if needed. If the Company exercises this purchase option, it will become the sole owner of the project again.

JPM’s capital contribution of $50.3 million was recorded as allocation to noncontrolling interests of $3.9 million and to liability associated with sale of tax benefits of $46.4 million.

Steamboat Hills Tax Monetization Transaction

On October 25, 2021, one of the Company’s wholly-owned subsidiaries that indirectly owns the Steamboat Hills Repower Geothermal power plant entered into a partnership agreement with a private investor. Under the transaction documents, the private investor acquired membership interests in the Steamboat Hills Repower Geothermal power plant project for an initial purchase price of $38.9 million and for which it will pay additional installments that are expected to amount to approximately $5.3 million. The Company continues 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, 2029 (“Steamboat Hills Target Flip Date”), the Company’s wholly-owned subsidiary, 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 Steamboat Hills 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 Steamboat Hills Target Flip Date, then for the period between the Steamboat Hills 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 Steamboat Hills 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.

McGinness Hills 3 Tax Monetization Transaction

On August 14, 2019, one of the Company's wholly-owned subsidiaries that indirectly owns the 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 $59.3 million and for which it will pay additional installments that are expected to amount to approximately $9.0 million and can reach up to $22.0 million based on the actual generation. The Company continues 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 ("MGH3 Target Flip Date"), one of the Company's wholly owned subsidiaries 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 MGH3 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 MGH3 Target Flip Date, then for the period between the MGH3 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 MGH3 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 Tax Monetization Transaction

On May 17, 2018, one of the Company's wholly-owned subsidiaries that indirectly owns the 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 $13.0 million. The Company continues 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 ("Tungsten Mountain Target Flip Date"), the Company's wholly-owned subsidiary, 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 Tungsten Mountain 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 Tungsten Mountain Target Flip Date, then for the period between the Tungsten Mountain 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 Tungsten Mountain 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 Tax Monetization Buyout

On July 31, 2024, the Company entered into an agreement with the third-party investor in Opal Geo, LLC ("Opal Geo"), a wholly-owned limited liability company formed solely for purpose of monetization of federal production tax credits and certain other tax benefits, to purchase 100% of the Class B membership interests in Opal Geo for a total of $9.8 million. As a result, the Company became the sole owner and beneficiary of all the economic benefits in Opal Geo, and continued to consolidate Opal Geo in its consolidated financial statements. The purchase of the Class B membership interest in Opal Geo was recorded as an equity transaction resulting in a reduction to the remaining balance of the related liability associated with sale of tax benefits, and the related noncontrolling interest of $1.7 million. The surplus of $0.5 million was charged to additional paid-in capital on the Company's consolidated balance sheets..

Transferable Production and Investment Tax Credits

Under the current IRA provision that includes a transferability provision for certain tax credits related to the clean production of energy, a reporting entity can monetize such credits through sale to a third-party. The option for transferability of credits applies to taxable years beginning after December 31, 2022. Several of the Company's projects, which are not currently part of a tax monetization transaction, generate eligible tax credits, such as ITCs and PTCs, that are eligible to be transferred to a third-party under the existing provisions of the IRA. The Company accounts for ITCs under ASC 740 through the "Income tax (provision) benefit" line in the consolidated statement of operations and comprehensive income. PTCs are accounted similarly to refundable or direct-pay credits outside of the "Income tax (provision) benefit" line with income recognized in the "Income attributable to sale of tax benefits" line in the consolidated statement of operations and comprehensive income. Income recognized related to the expected sale of such transferable PTCs during the years ended December 31, 2025 and 2024, was $17.9 million, and $23.4 million, net of discount, respectively. Tax benefits recognized under Income tax (provision) benefit related to transferable ITCs during the years ended December 31, 2025 and 2024, were $44.1 million and $47.7 million, net of discount, respectively.

NOTE 13 — ASSET RETIREMENT OBLIGATION

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

	Year Ended December 31,		
	2025	2024	2023
	(Dollars in thousands)		
Balance at beginning of year	$ 129,651	$ 114,370	$ 97,660
Revision in estimated cash flows	(8,071)	(893)	2,056
Liabilities incurred and acquired	5,664	8,427	8,490
Accretion expense	8,330	7,747	6,164
Balance at end of year	$ 135,574	$ 129,651	$ 114,370

NOTE 14 — STOCK-BASED COMPENSATION

The Company makes an estimate of expected forfeitures and recognizes compensation costs only for those stock-based awards expected to vest. As of December 31, 2025, the total future compensation cost related to unvested stock-based awards that are expected to vest is $14.0 million, which will be recognized over a weighted average period of 1.15 years.

During the years ended December 31, 2025, 2024 and 2023, the Company recorded compensation related to stock-based awards as follows:

	Year Ended December 31,		
	2025	2024	2023
	(Dollars in thousands)		
Cost of revenues	$ 8,757	$ 9,169	$ 6,899
Selling and marketing expenses	854	921	866
Research and development expenses	222	144	94
General and administrative expenses	9,557	9,963	7,620
Total stock-based compensation expense	19,390	20,197	15,479
Tax effect on stock-based compensation expense	1,964	1,998	1,598
Net effect of stock-based compensation expense	$ 17,426	$ 18,199	$ 13,881

During the fourth quarter of 2025, 2024 and 2023, the Company evaluated the trends of the employees stock-based award forfeiture rate and determined that the actual rates are 11.3%, 10.9% and 11.6%, respectively. This represents an increase (decrease) of 3.7%, (6.0)%, and 0.9%, 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 Black-Merton-Scholes methodology implemented using binomial Tree option pricing model. The dividend yield forecast is expected to be at least 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, 2025. 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,		
	2025	2024	2023
For stock based awards issued by the Company:			
Risk-free interest rates	4.0 %	4.5 %	4.2 %
Expected lives (in weighted average years)	2.1	2.2	2.5
Dividend yield	0.7 %	0.7 %	0.6 %
Expected volatility (weighted average)	28.8 %	31.9 %	38.2 %

The Company estimated the forfeiture rate (on a weighted average basis) as follows:

	Year Ended December 31,		
	2025	2024	2023
Weighted average forfeiture rate	8.8 %	8.2 %	8 %

Stock-based Awards

The 2018 Incentive Compensation Plan

The 2018 Incentive Plan provides for the grant of the following types of awards: incentive stock options, restricted stock units ("RSUs"), stock appreciation rights ("SARs"), Performance Stock Units ("PSUs), stock units, performance awards, phantom stock, incentive bonuses and other possible related dividend equivalents to employees of the Company, directors and independent contractors. SARs, RSUs and PSUs 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, or 33.3% on each of the first, second and third anniversaries of the grant date. SARs, RSUs and PSUs 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. In June 2022, the 2018 Incentive Compensation Plan was amended and restated to increase the number of shares authorized for issuance (which was initially 5,000,000) by 1,700,000 shares, to change the fungible ratio, and to implement a one year mandatory minimum vesting period, and in May 2024 amended and restated again to increase the number of shares authorized for issuance by 1,400,000 shares.

As of December 31, 2025, 2,145,870 shares of the Company's common stock are available for future grants under the 2018 Incentive Plan.

In March 2025, the Company granted certain members of its management and employees an aggregate of 210,961 restricted stock units ("RSUs") and 45,190 performance stock units ("PSUs") under the Company's 2018 Incentive Compensation Plan. The RSUs and PSUs have vesting periods of between 1 to 3 years from the grant date.

The fair value of each RSU and PSU on the grant date was $68.9 and $70.9, respectively. The Company calculated the fair value of each RSU and PSU on the grant date using the Black-Merton-Scholes using binomial Tree option pricing model, and the Monte Carlo simulation, based on the following assumptions:

Risk-free interest rates	3.95%	–	4.08%
Expected life (in years)	1	–	3
Dividend yield	0.69%		
Expected volatility (weighted average)	27.0%	–	31.0%

In March 2024, the Company granted certain members of its management and employees an aggregate of 209,563 RSUs and 61,197 PSUs under the Company's 2018 Incentive Compensation Plan. The RSUs and PSUs have vesting periods of between 1 to 3 years from the grant date.

The fair value of each RSU and PSU on the grant date was $64.9 and $64.0, respectively. The Company calculated the fair value of each RSU and PSU on the grant date using the Black-Merton-Scholes using binomial Tree option pricing model, based on the following assumptions:

Risk-free interest rates	4.27% – 4.94%
Expected life (in years)	1 – 3
Dividend yield	0.73%
Expected volatility (weighted average)	28.0% – 34.0%

In March 2023, the Company granted certain members of its management and employees an aggregate of 174,422 RSUs and 35,081 PSUs under the Company's 2018 Incentive Compensation Plan. The RSUs and PSUs have vesting periods of between 1 to 4 years from the grant date. The fair value of each RSU and PSU on the grant date was $79.9 and $79.6, respectively. The Company calculated the fair value of each RSU and PSU on the grant date using the Black-Merton-Scholes using binomial Tree option pricing model based on the following assumptions:

Risk-free interest rates	3.86% — 4.68%
Expected life (in years)	1 — 4
Dividend yield	0.59%
Expected volatility (weighted average)	36.0% — 42.2%

In May 2023, the Company granted its directors an aggregate of 10,852 RSUs under the Company's 2018 Incentive Compensation Plan. The RSUs have vesting periods 1 year from the grant date. The fair value of each RSU on the grant date was $82.9. The Company calculated the fair value of each RSU and PSU on the grant date using the Black-Merton-Scholes using binomial Tree option pricing model based on the following assumptions:

Risk-free interest rates	4.70%
Expected life (in years)	1
Dividend yield	0.56%
Expected volatility (weighted average)	34.80%

Information on the awards outstanding and the related weighted average exercise price as of and for the years ended December 31, 2025, 2024 and 2023 are presented in the table below:

	Year Ended December 31,					
	2025		2024		2023	
	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	1,380	$ 69.91	1,483	$ 52.57	1,810	$ 60.08
Granted:						
RSUs [1]	248	—	242	—	189	—
PSUs [2]	45	—	61	—	35	—
Exercised	(835)	69.63	(377)	62.91	(492)	56.00
Forfeited	(25)	71.15	(29)	64.16	(59)	54.09
Expired	—	—	—	—	—	—
Outstanding at end of year	813	70.70	1,380	69.91	1,483	52.57

Options and SARs exercisable at end of year [3]	101	70.26	614	69.41	606	66.81
Weighted-average fair value of awards granted during the year		$ 70.99		$ 64.95		$ 79.98

[1] An RSU represents the right to receive one share of common stock once certain vesting conditions are met. The value of an RSU approximates the value of the underlying stock.

[2] The PSUs shall be paid out based on achievement of three-year relative total stockholder return compared to other companies in the S&P 500 index or based on achievement of three-year megawatt COD capacity targets.

[3] 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.

The following table summarizes information about stock-based awards outstanding at December 31, 2025 (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
$ —	611	1.0	$ 67,522			$ —
67.54	3	0.9	113	3	0.9	113
69.14	45	0.4	1,869	45	0.4	1,869
71.15	154	2.2	6,048	53	2.2	2,084
90.28	1	1.0	12	1	1.0	12
	813	1.2	$ 75,564	101	1.3	$ 4,078

The following table summarizes information about stock-based awards outstanding at December 31, 2024 (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
$ —	537	1.0	$ 36,349	—	0.0	$ —
63.40	45	1.5	196	45	1.5	196
67.54	7	1.8	1	7	1.9	1
68.34	47	1.4	—	47	1.4	—
69.14	335	1.4	—	335	1.4	—
71.15	385	3.2	—	160	3.2	—
71.71	4	0.6	—	4	0.6	—
76.43	5	0.9	—	5	0.9	—
76.54	9	2.9	—	6	2.9	—
78.53	6	2.3	—	5	2.4	—
90.28	1	2.0	—	1	2.0	—
	1,380	1.8	$ 36,546	614	1.9	$ 197

The aggregate intrinsic value in the above tables represents the total pretax intrinsic value, based on the Company's stock price of $110.47 and $67.72 as of December 31, 2025 and 2024, 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, 2025 and 2024 was 101,426 and 51,940, respectively.

The total pretax intrinsic value of options exercised during the year ended December 31, 2025 and 2024 was $27.1 million and $3.4 million, respectively, based on the average stock price of $85.9 and $72.0 during the years ended December 31, 2025 and 2024, respectively.

NOTE 15 — INTEREST EXPENSE, NET

The components of interest expense are as follows:

	Year Ended December 31,		
	2025	2024	2023
	(Dollars in thousands)		
Interest related to sale of tax benefits	$ 19,634	$ 18,149	$ 15,289
Interest expense	150,333	130,605	$ 100,853
Less — amount capitalized	(28,116)	(14,723)	$ (17,261)
	$ 141,851	$ 134,031	$ 98,881

NOTE 16 — 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,		
	2025	2024	2023
	(Dollars in thousands)		
U.S	$ 17,634	$ 36,984	$ 53,984
Non-U.S. (foreign)	88,114	78,393	85,101
Total income from continuing operations, before income taxes and equity in losses	$ 105,748	$ 115,377	$ 139,085

The components of the provision (benefit) for income taxes, net are as follows:

	Year Ended December 31,		
	2025	2024	2023
	(Dollars in thousands)		
Current:			
Federal	$ 769	$ 961	$ 672
State	666	1,478	(1,806)
Foreign	21,435	22,075	35,379
Total current income tax expense	$ 22,870	$ 24,514	$ 34,245
Deferred:			
Federal	(50,505)	(44,992)	(12,780)
State	(4,174)	(5,893)	6,041
Foreign	11,527	10,082	(21,523)
Total deferred tax provision (benefit)	(43,152)	(40,803)	(28,262)
Total income provision (benefit)	$ (20,282)	$ (16,289)	$ 5,983

The following table is a reconciliation of the income tax provision and the U.S. federal statutory tax rate to the Company's effective income tax rate (Dollars in thousands):

	Year Ended December 31,					
	2025		2024		2023	
US federal statutory tax rate	$ 22,224	21.0 %	$ 24,228	21.0 %	$ 29,207	21.0 %
Domestic federal:						
Cross-border tax laws:						
Global intangible low-taxed income	(864)	(0.8)	1,696	1.5	392	0.3
Other	(2,194)	(2.1)	(731)	(0.6)	46	—
Tax credits:						
Investment tax credits	(47,671)	(45.0)	(49,440)	(42.7)	(19,425)	(14.0)
Nontaxable or nondeductible items:						
Transferable tax credit sales	(3,680)	(3.5)	(4,921)	(4.3)	(2,394)	(1.7)
Noncontrolling interest	(549)	(0.5)	(1,411)	(1.2)	(1,341)	(1.0)
Other	(1,387)	(1.3)	(374)	(0.3)	122	0.1
Other Adjustments:	513	0.4	(456)	(0.4)	415	0.3
State and local taxes, net of federal income tax effect [(a)]	(1,836)	(1.7)	(844)	(0.7)	3,345	2.4
Foreign tax effects:						
Cayman:						
Other	1,428	1.3	1,416	1.2	1,574	1.1
Dominica:						
Foreign rate differential	(4,200)	(4.0)	275	0.2	—	—
Guatemala:						
Foreign rate differential	(2,045)	(1.9)	(2,153)	(1.9)	(1,847)	(1.3)
Other	(256)	(0.2)	(552)	(0.5)	(195)	(0.1)
Israel:						
Nondeductible stock compensation	1,356	1.3	1,890	1.6	1,024	0.7
Deferred income	—	—	1,559	1.4	(1,559)	(1.1)
Exchange rate differential	1,018	1.0	—	—	—	—
Intra-entity transfers	—	—	(1,162)	(1.0)	(669)	(0.5)
Tax rate change	—	—	—	—	(558)	(0.4)
Withholding tax	4,113	3.9	—	—	—	—
Other	(379)	(0.4)	(986)	(0.9)	27	—
Kenya:						
Foreign rate differential	6,295	5.9	6,121	5.3	10,755	7.8
Exchange rate differential	—	—	11,101	9.6	(8,398)	(6.0)
Nondeductible items	1,300	1.2	(889)	(0.8)	570	0.4
Tax rate change	—	—	—	—	(7,417)	(5.3)
Other	818	0.8	886	0.8	1,391	1.0
New Zealand:						
Pillar two	1,622	1.5	—	—	—	—
Other	69	0.1	(450)	(0.4)	8	—
Other foreign jurisdictions:	(83)	(0.1)	(1,691)	(1.5)	(1,205)	(0.9)

Change in unrecognized tax benefits	4,106	3.9	599	0.5	2,115	1.5
Income tax provision/(benefit) and effective tax rate	$ (20,282)	(19.2)%	$ (16,289)	(14.1)%	$ 5,983	4.3 %

[a] During the tax years ended December 31, 2025, 2024 and 2023, state taxes in California comprised more than 50% of the total state and local taxes, net of federal income tax effect.

The net deferred tax assets and liabilities consist of the following:

	December 31,	
	2025	2024
	(Dollars in thousands)	
Deferred tax assets (liabilities):		
Net foreign deferred taxes, primarily depreciation	$ (42,336)	$ (36,955)
Depreciation	24,313	(38,831)
Intangible drilling costs	(25,903)	(19,307)
Net operating loss carryforward - U.S.	21,875	22,760
Tax monetization transaction	(62,200)	(53,950)
Right-of-use assets	(8,063)	(7,317)
Lease liabilities	6,918	5,949
Production and investment tax credits	107,774	118,461
Foreign tax credits	6,030	30,919
Withholding tax	(16,276)	(19,308)
Basis difference in partnership interest	(13,157)	(13,586)
Excess business interest	1,723	18,122
Sale and leaseback transaction	52,478	54,480
Other assets	11,202	14,512
Accrued liabilities and other	8,484	12,071
Total	72,862	88,020
Less - valuation allowance	(2,620)	(2,700)
Total, net	$ 70,242	$ 85,320

The following table presents income taxes paid, net of refunds:

	Year Ended December 31,		
	2025	2024	2023
	(Dollars in thousands)		
U.S. federal:	$ 850	$ (38)	$ 1,000
California	1,890	425	310
Other U.S. state and local	91	(776)	1,328
Foreign:			
Israel	(876)	2,525	(3,462)
Kenya	6,681	22,801	23,550
Guadeloupe	305	326	2,637
Other	905	920	887
Total income taxes paid, net of refunds	$ 9,846	$ 26,183	$ 26,250

The following table presents a reconciliation of the beginning and ending valuation allowance:

	Year Ended December 31,	
	2025	2024
	(Dollars in thousands)	
Balance at beginning of the year	$ 2,700	$ 2,870
Additions to valuation allowance	0	0
Release of valuation allowance	(80)	(170)
Balance at end of the year	$ 2,620	$ 2,700

At December 31, 2025, the Company had U.S. federal net operating loss ("NOL") carryforwards of approximately $30.4 million, all of which was generated before 2018 and expires by 2038.

At December 31, 2025, the Company had PTCs in the amount of $107.8 million. These PTCs are available for a 20-year period and begin to expire in 2027. At December 31, 2025, the Company had no remaining ITCs. At December 31, 2025, the Company had U.S. foreign tax credits ("FTCs") in the amount of $6.0 million. These FTCs are available for a 10-year period, and begin to expire in 2028.

At December 31, 2025, the Company had state NOL carryforwards of approximately $238.3 million, $233.7 million which expire between 2026 and 2045 and $4.6 million 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 $2.6 million and $2.7 million is recorded against the U.S. deferred tax assets as of December 31, 2025 and 2024, 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 $0.1 million is due to the ability to utilize attributes that previously have been fully valued. The Company is maintaining a valuation allowance of $2.6 million against a portion of its state NOLs and capital loss carryforward 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 $113.9 million and $49.9 million, respectively. A valuation allowance of $1.8 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.

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. We have elected and applied the tax law ordering approach when considering GILTI as part of our valuation allowance.

The Company uses the flow-through method to account for investment tax credit earned on eligible battery storage projects. Under this method, the investment tax credits are recognized as a reduction to income tax expense in the year they are earned rather than a reduction in the asset basis.

The following table presents the deferred taxes on the balance sheet as of the dates indicated:

	Year Ended December 31,	
	2025	2024
	(Dollars in thousands)	
Non-current deferred tax assets	$ 138,903	$ 153,936
Non-current deferred tax liabilities	(68,661)	(68,616)
Non-current deferred tax assets, net	70,242	85,320
Uncertain tax benefit offset [(1)]	(95)	(95)
	$ 70,147	$ 85,225

[(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, 2025, 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. Accordingly, as of December 31, 2025, the Company has accrued $12.6 million of foreign withholding taxes on future distributions of foreign earnings.

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, 2025 and 2024, there are $10.4 million and $6.3 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,	
	2025	2024
	(Dollars in thousands)	
Balance at beginning of year	$ 4,657	$ 6,930
Additions based on tax positions taken in prior years	3,348	1,260
Additions based on tax positions taken in the current year	3,873	431
Reduction based on tax positions taken in prior years	(3,176)	(3,964)
Reduction based on tax positions taken in the current year	(265)	—
Balance at end of year	$ 8,437	$ 4,657

The Company and its U.S. subsidiaries file consolidated income tax returns for federal and state (where applicable) purposes. As of December 31, 2025, 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 2007-2024 and by local state jurisdictions for the years 2010-2024. 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	2023	–	2025
Kenya	2020	–	2025
Guatemala	2021	–	2025
Honduras	2019	–	2025
Guadeloupe	2025	–	2025

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

On August 16, 2022, the Inflation Reduction Act was signed into law in the United States. The Company believes that the construction and operations of its geothermal power plants, recovered energy-based power plants, battery energy storage systems and solar PV will benefit in the future from the IRA and enhance the economic feasibility of projects in the United States. PTCs can be generated from 3.00 cents per kWh, once the Wages & Apprenticeship rules are met, and if bonus credit requirements are met the credit could rise up to 3.63 cents per kWh. ITCs can be earned on investments from 30.0%, once the Wages & Apprenticeship rules are met, and if bonus credit requirements are met the credit could rise up to 50.0%. Battery Energy Storage Systems are eligible for ITC for projects placed-in-service after December 31, 2022. In addition, the Company can now monetize PTCs and ITCs earned by transferring the credits to a third-party without having to enter into a tax equity transaction.

On July 4, 2025, the OBBBA was enacted into law in the United States. The OBBBA includes significant provisions, such as the permanent extension of certain expiring provisions of the Tax Cuts and Jobs Act of 2017 and numerous changes to the energy tax credits initially introduced and expanded under the IRA. The OBBBA allows for geothermal and battery storage to qualify for 100% PTC or ITC related to projects that start construction by the end of December 2033, 75% PTC or ITC by the end of December 2034 and 50% PTC or ITC by the end of December 2035. In order to qualify for 100% energy credit, solar projects must start construction by July 4, 2026 and be placed-in-service within four years, or start construction after July 3, 2026 and be placed-in-service by December 31, 2027. The law seeks to limit content from foreign entities of concern ("FEOC") used in energy related projects that start construction after December 31, 2025. Under the new FEOC rules, a U.S. energy project can only receive specific tax credits if the project's equipment from certain FEOC- related entities does not exceed set amounts, and the rules disqualify other credits from applying to US-made products that contain too many inputs from certain FEOC- related entities. The rules also prevent a company from receiving specific tax credits if it relies too much on investment or material assistance from certain FEOC- related entities, including in circumstances where a contract, license, or other arrangement gives an FEOC- related entity effective control over the company or its projects or products.

The Organization for Economic Co-operation and Development ("OECD") issued a framework to implement a global minimum corporate tax of 15% for companies with global revenues and profits above certain thresholds (referred to as Pillar 2). Certain aspects of Pillar 2 became effective January 1, 2024, and other aspects became effective January 1, 2025. Effective January 1, 2025, the Company met the revenue threshold requirements and is now subject to Pillar 2. The impact of Pillar 2 resulted in an income tax expense of $1.9 million for the twelve months ended December 31, 2025.

In January 2026, the OECD released a "side-by-side" package introducing new safe harbors and providing an exemption for U.S. based multi-national companies from parts of the global minimum corporate tax. The updated model rules will need to be incorporated into local tax legislation to be effective. The Company will continue to evaluate the impact of the proposed legislative changes as new guidance becomes available.

Income Taxes Related to Foreign Operations

Dominica – On June 25, 2025, the Company received a letter from the Dominica Ministry of Finance stating that during the construction phase of our BOT project in Dominica, the Company would enjoy a 0% income tax rate. Once this project reaches commercial operation, the Company will enjoy a 10% preferential income tax rate granted to the Company by the Dominica government.

Guadeloupe — The Company's operations in Guadeloupe are taxed at a maximum rate of 26.5% in 2021, and 25% in 2022 and beyond.

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 pays income tax of 7% on its Electricity revenues.

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, which was in September 2017.

Israel — The Company's operations in Israel through its wholly owned Israeli subsidiary, Ormat Systems Ltd. ("Ormat Systems"), are taxed at a reduced corporate tax rate under the "Benefited Enterprise" tax regime of the Encouragement of Capital Investments Law, 1959 (the "Investment Law"), with respect to two of its investment programs. In January 2011, new legislation amending the Investment Law by adding, inter alia, the Preferred Enterprise Regime was enacted. Under the Preferred Enterprise Regime, a uniform reduced corporate tax rate would apply to all qualified income of certain industrial companies, as opposed to the Investment Law 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 is 16% for qualifying income.

Kenya — In June 2023, the President of Kenya signed into law the 2023 Finance Act ("Finance Act"). The Finance Act, among several other changes, reduced the statutory corporate income tax rate for Branches from 37.5% to 30%, introduced a Branch Profits tax based on the change in Net Assets and limits interest deductions to 30% of EBITDA. The Finance Act also reduced the corporate tax rate on Branches from 37.5% to 30.0%. The Company implemented this change and recorded an associated benefit during 2023.

NOTE 17 — BUSINESS SEGMENTS

The Company has three reporting segments: the Electricity segment, the Product segment and the Energy Storage segment. These segments are managed and reported separately as each offers different products and serves different markets. Under the Electricity segment, the Company builds, owns and operates geothermal, solar PV and recovered energy-based power plants in the United States, and geothermal power plants in foreign countries, and sells the electricity generated by those power plants. Under the Product segment, the Company designs, manufactures and sells equipment for geothermal and recovered energy-based electricity generation and provide services relating to the engineering, procurement and construction of geothermal and recovered energy-based power plants. Under the Energy Storage segment, the Company owns and operates grid connected In-Front-of-the-Meter battery energy storage systems, which provide capacity, energy and/or ancillary services directly to the electric grid.

The accounting policies of the segments are the same as those described under Note 1 to the condensed consolidated financial statements. Transfer prices between the segments were determined on current market values or cost plus markup of the seller's segment. The Company's Chief Operating Decision Maker ("CODM") is comprised of its CEO and CFO. To evaluate segment performance and allocate the Company's resources, the CODM uses segment measures of gross profit and operating income. The CODM reviews budget-to-actual variances of both profit measures on a monthly basis when making decisions about allocation of the Company's resources to the segments.

Summarized financial information concerning the Company's reportable segments is shown in the following tables, including the Company's disaggregated revenues from contracts with customers as required by ASC 606, Revenue from Contracts with Customers ("ASC 606"). Total consolidated revenues, gross profit (loss) and operating income (loss) of the Company's business segments exclude intersegment revenues, gross profit (loss) and operating income (loss) as these activities are eliminated in consolidation and are not included in CODM's evaluation of performance of each segment.

	Electricity	Product	Energy Storage	Total
	(Dollars in thousands)			
Year Ended December 31, 2025:				
Revenues from external customers:				
United States [1]	$ 500,377	$ 10,954	$ 78,957	$ 590,288
Foreign [2]	193,523	205,732	—	399,255
Net revenues from external customers	693,900	216,686	78,957	989,543

Less:				
Depreciation and amortization expenses [3]	236,278	10,377	29,365	276,020
Other cost of revenues expenses [4]	259,711	160,294	20,833	440,838
Segment gross profit (loss)	197,911	46,015	28,759	272,685
Less:				
Segment operating expenses [5]	83,284	22,613	(2,436)	103,460
Segment operating income (loss)	$ 114,627	$ 23,402	$ 31,195	$ 169,225
Total depreciation and amortization expense [6]	250,787	11,751	29,586	292,124
Segment assets at period end [7] [*]	5,338,343	276,205	631,960	6,246,508
Expenditures for long-lived assets	446,843	13,132	159,801	619,776
* Including unconsolidated investments	162,111	—	—	162,111
Year Ended December 31, 2024:				
Revenues from external customers:				
United States [1]	$ 510,645	$ 8,969	$ 37,729	$ 557,343
Foreign [2]	191,619	130,692	—	322,311
Net revenues from external customers	702,264	139,661	37,729	879,654
Less:				
Depreciation and amortization expenses [3]	218,252	10,363	20,262	248,876
Other cost of revenues expenses [4]	241,274	103,548	13,336	358,159
Segment gross profit (loss)	242,738	25,750	4,131	272,619
Less:				
Segment operating expenses [5]	80,832	15,428	3,889	100,149
Segment operating income (loss)	$ 161,906	$ 10,322	$ 242	$ 172,470
Total depreciation and amortization expense [6]	230,957	11,693	20,213	262,863
Segment assets at period end [7] [*]	4,983,069	229,687	453,468	5,666,224
Expenditures for long-lived assets	375,540	10,005	102,133	487,678
* Including unconsolidated investments	144,585	—	—	144,585
Year Ended December 31, 2023:				
Revenues from external customers:				
United States [1]	$ 473,323	$ 7,610	$ 28,894	$ 509,827
Foreign [2]	193,444	126,153	—	319,597
Net revenues from external customers	666,767	133,763	28,894	829,424
Less:				
Depreciation and amortization expenses [3]	189,194	5,358	14,621	209,173
Other cost of revenues expenses [4]	233,355	110,444	12,434	356,233
Segment gross profit (loss)	244,218	17,961	1,839	264,018
Less:				
Segment operating expenses [5]	75,384	14,425	7,624	97,433
Segment operating income (loss)	$ 168,834	$ 3,536	$ (5,785)	$ 166,585
Total depreciation and amortization expense [6]	199,344	10,908	14,545	224,797
Segment assets at period end [7] [*]	4,652,392	199,897	355,990	5,208,279
Expenditures for long-lived assets	474,592	20,599	123,192	618,383
* Including unconsolidated investments	125,439	—	—	125,439

(1) Electricity segment revenues in the United States are all accounted under lease accounting, except for $143.5 million, $153.2 million, and $124.7 million for the years 2025, 2024 and 2023, respectively, which are accounted under ASC 606. Product and Energy Storage segment revenues in the United States are accounted under ASC 606, as further described under Note 1 to the consolidated financial statements, except for Energy Storage revenues of $18.8 million, $4.2 million and none for the years ended December 31, 2025, 2024 and 2023, respectively, that are accounted under lease accounting.

(2) Electricity segment revenues in foreign countries are all accounted under lease accounting. Product revenues in foreign countries are accounted under ASC 606 as further described under Note 1 to the consolidated financial statements.

(3) Depreciation and amortization expense amounts align with the segment-level information that is regularly provided to the CODM, and do not include intersegment transactions. Depreciation and amortization expenses included in the segment measure of gross profit are related to the specific tangible and intangible assets associated with each of the reportable segment.

(4) Other cost of revenues expenses for each reportable segment include:

Electricity: primarily cost of manpower, utilities, repair and maintenance, royalties, and property taxes.

Products: primarily cost of raw materials and finished goods used in manufacturing, manpower, transportation, and third-party subcontractors.

Energy Storage: primarily cost of manpower, utilities, and insurance.

(5) Segment operating expenses include research and development expenses, selling and marketing expenses, and general and administrative expenses such as manpower, depreciation and amortization, legal and professional services. Such expenses do not include intersegment transactions. Segment operating expenses related to the Energy Storage segment are directly related to this segment. Segment operating expenses related to the Electricity and Product segments are allocated between these two segments based on their weighted contribution to revenues, except for certain specific expenses or gains that are specifically allocated to one of these segments, as applicable, such as impairment of long-lived assets, write-off of unsuccessful exploration activities, and other operating income.

(6) Total depreciation and amortization expenses for each segment are related to the specific tangible and intangible assets associated with the respective reportable segment.

(7) Electricity segment assets include goodwill in the amount of $163.6 million , $146.4 million and $85.9 million as of December 31, 2025, 2024 and 2023, respectively. Energy Storage segment assets include goodwill in the amount of $4.6 million , $4.6 million and $4.6 million as of December 31, 2025, 2024 and 2023, respectively. No goodwill is included in the Product segment assets as of December 31, 2025, 2024 and 2023.

Reconciling information between reportable segments and the Company's consolidated totals is shown in the following table:

	Year Ended December 31,		
	2025	2024	2023
	(Dollars in thousands)		
Reconciliation of profit or loss (segment gross profit):			
Total segment gross profit (loss)	$ 272,685	$ 272,619	$ 264,018
Less operating expenses:			
Research and development expenses	6,304	6,501	7,215
Selling and marketing expenses	18,898	17,694	18,306
General and administrative expenses	79,592	80,119	68,179
Other operating income	(14,844)	(9,375)	—
Write-off of long-lived assets	12,064	1,280	—
Write-off of unsuccessful exploration activities	1,446	3,930	3,733
Operating income	$ 169,225	$ 172,470	$ 166,585
Interest income	6,015	7,883	11,983
Interest expense, net	(141,851)	(134,031)	(98,881)
Derivatives and foreign currency transaction gains (losses)	5,248	(4,187)	(3,278)

Income attributable to sale of tax benefits	66,726	73,054	61,157
Other non-operating income (expense), net	385	188	1,519
Total consolidated income before income taxes and equity in earnings (losses) of investees	$ 105,748	$ 115,377	$ 139,085

Reconciliation of profit or loss (segment operating income):			
Total segment operating income	$ 169,225	$ 172,470	$ 166,585
Interest income	6,015	7,883	11,983
Interest expense, net	(141,851)	(134,031)	(98,881)
Derivatives and foreign currency transaction gains (losses)	5,248	(4,187)	(3,278)
Income attributable to sale of tax benefits	66,726	73,054	61,157
Other non-operating income (expense), net	385	188	1,519
Total consolidated income before income taxes and equity in earnings (losses) of investees	$ 105,748	$ 115,377	$ 139,085

The Company sells electricity, products, and provides energy storage 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,		
	2025	2024	2023
	(Dollars in thousands)		
Revenues from external customers attributable to:			
United States	$ 590,288	$ 557,343	$ 509,827
Indonesia	1,489	7,616	26,732
Kenya	117,422	114,066	109,217
Dominica	48,931	—	—
Turkey	5,147	3,013	2,469
Guatemala	28,014	28,955	30,174
New Zealand	128,817	78,665	66,526
Honduras	28,658	30,304	31,589
Other foreign countries	40,777	59,692	52,889
Consolidated total	$ 989,543	$ 879,654	$ 829,424

The following table presents information on geographic area of long-lived assets:

	Year Ended December 31,		
	2025	2024	2023
	(Dollars in thousands)		
Long-lived assets (primarily power plants and related assets) located in:			
United States	$ 3,897,443	$ 3,464,011	$ 3,085,892
Kenya	363,422	382,738	377,563
Guadeloupe	158,627	112,375	101,728
Other foreign countries	347,697	333,306	276,300
Consolidated total	$ 4,767,189	$ 4,292,430	$ 3,841,483

The following table presents revenues from major customers:

	Year Ended December 31,					
	2025		2024		2023	
	Revenues	%	Revenues	%	Revenues	%
	(Dollars in thousands)		(Dollars in thousands)		(Dollars in thousands)	
Southern California Public Power [1]	$ 175,999	17.8 %	$ 181,120	20.6 %	$ 181,656	21.2 %
Sierra Pacific Power Company and Nevada Power Company [1][2]	136,730	13.8	133,108	15.1	116,797	14.1 %
KPLC [1]	117,422	11.9	114,066	13.0	109,217	13.2 %

[1] Revenues reported in Electricity segment.

[2] Subsidiaries of NV Energy, Inc.

NOTE 18 — TRANSACTIONS WITH RELATED ENTITIES

There were no transactions between the Company and related entities, other than those disclosed below and elsewhere in these consolidated financial statements. The Company considers entities in which it accounts for its ownership in those entities under the equity method as related entities. Refer to Note 5, Investment in Unconsolidated Companies, for further information on such investments.

In 2023, the Company signed a contract for supply of key equipment to the Ijen project in Indonesia, which is jointly developed by Medco and the Company. The Ijen project is owned by PT Medco Cahaya Geothermal ("MCG"), in which the Company holds ownership of 49%, as further described under Note 5, Investment in Unconsolidated Companies, to the consolidated financial statements. Product revenues for the years ended December 31, 2025, 2024 and 2023, included revenues related to sale of spare parts and the supply agreement for the Ijen project in Indonesia in the amount of $1.2 million, $7.4 million, and $24.0 million, respectively. As of December 31, 2025 and 2024, there were no amounts due from MCG.

There were no Product revenues or amounts due related to the Sarulla project for the years ended December 31, 2025 and 2024, and as of December 31, 2025 and 2024, respectively. Products revenues for the year ended December 31, 2023, included revenues in the amount of $1.6 million related to a project to the Sarulla project in Indonesia.

NOTE 19 — 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, subject to the maximum amount permitted by law. In 2025, 2024 and 2023, the Company matched employee contributions, after completion of one year of service, up to a maximum of 6% of the employee's annual salary. The Company's contributions to the Plan were $4.6 million, $4.3 million and $3.9 million for the years ended December 31, 2025, 2024 and 2023, 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 are $5.8 million and $5.9 million at December 31, 2025 and 2024, 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, 2025, 2024 and 2023 were $2.8 million, $2.9 million and $2.2 million, respectively, which are net of income (loss) amounting to $0.3 million, $0.4 million, and $(0.2) 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, not including amounts already funded into the severance funds to-date:

	(Dollars in thousands)
Year ending December 31:	
2026	$ 668
2027	199
2028	479
2029	720
2030	502
2031-2048	2,912
Total	$ 5,480

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 20 — COMMITMENTS AND CONTINGENCIES

Geothermal Resources

The Company, through its project subsidiaries in the United States and other foreign locations, 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 $31.0 million, $32.1 million and $30.9 million for the years ended December 31, 2025, 2024 and 2023, 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 $286.0 million at December 31, 2025. Management does not expect any material losses to result from these letters of credit because performance is not expected to be required.

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, 2025, total obligations related to such supplier agreements were $355.1 million (out of which $106.7 million relate to construction-in-process). All such obligations are payable in 2026.

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, 2025, 2024 and 2023. 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 of 5.9%. The cap at December 31, 2025 and 2024, amounted to $2.7 million and $2.6 million, respectively, of which approximately $1.8 million and $1.6 million, represents the interest portion, as defined above, for 2025 and 2024, respectively.

Lease Commitments

The Company's lease commitments are detailed under Note 21, Leases to the consolidated financial statements.

Contingencies

In February 2025, Engie Resources, LLC and certain of its affiliates filed an action against the Company's wholly-owned subsidiary in the United States District Court for the Northern District of Texas, which was later re-filed in the Texas Business Court. The complaint alleges that the Company breached its contractual obligations, including certain indemnity obligations, under certain service agreements with or involving the plaintiffs, by failing to properly schedule responsive reserve service on behalf of the plaintiffs during the power crisis in Texas in February 2021. The plaintiffs originally sought $47.5 million in damages. In December 2025, the plaintiffs amended their complaint to add claims related to the same facts, seeking an additional $7.0 million in damages. The Company considers it has strong legal defenses and intends to vigorously defend itself against the claims and take all necessary legal action to have them dismissed. The Company has filed a motion for summary judgment with a hearing date set for March 20, 2026. Trial is scheduled to begin subject to the outcome of the motion for summary judgment on May 18, 2026. No amounts have been accrued for potential losses under this matter, as the Company believes the probability of the claimant receiving a material award is low and it cannot currently reasonably predict the outcome of the proceedings, which is inherently uncertain.

Additionally, from time to time, the Company is named as a party to other various 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 21 — LEASES

The Company is a lessee in operating transactions primarily consisting of land leases for its exploration and development activities and storage activities. Additionally, the Company is a lessee in finance lease transactions for its fleet vehicles. The Company is a lessor primarily 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", and "Leases".

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,		
	2025	2024	2023
	(Dollars in thousands)		
Lease cost:			
Finance lease cost:			
Amortization of right-of-use assets	$ 1,821	$ 1,388	$ 1,922
Interest on lease liabilities	206	143	168
Operating lease cost	6,665	5,657	4,771
Short-term and variable lease cost	10,220	6,738	6,741
Total lease cost	$ 18,912	$ 13,926	$ 13,602
Other information:			
Cash paid for amounts included in the measurement of lease liabilities:			
Operating cash flows for finance leases	$ 206	$ 143	$ 168
Operating cash flows for operating leases	7,909	10,526	4,448
Financing cash flows for finance leases	1,840	1,383	1,963
Right-of-use assets obtained in exchange for new finance lease liabilities	3,677	761	1,671

Right-of-use assets obtained in exchange for new operating lease liabilities	12,174	12,599	4,731

	December 31,	
Additional information as of the end of the year:	2025	2024
Weighted-average remaining lease term — finance leases (in years)	12.3	13.4
Weighted-average remaining lease term — operating leases (in years)	14.9	16.3
Weighted-average discount rate — finance leases (in percentage)	6 %	6 %
Weighted-average discount rate — operating leases (in percentage)	5 %	5 %

Future minimum lease payments under non-cancellable leases as of December 31, 2025 were as follows:

	Operating Leases	Finance Leases	Financing Liability [1]
	(Dollars in thousands)		
Year ending December 31,			
2026	$ 6,098	$ 551	$ 22,675
2027	4,879	1,885	20,815
2028	3,914	1,127	20,578
2029	3,211	938	23,165
2030	2,477	399	19,856
Thereafter	30,608	29	230,986
Total future minimum lease payments	51,187	4,929	338,075
Less imputed interest	16,663	402	121,679
Total	$ 34,524	$ 4,527	$ 216,396

[1] Financing liability was assumed as part of the Terra-Gen business combination transaction in 2021 as further described under Note 11 to the consolidated financial statements, and is related to the sale and lease-back transaction of the Dixie Valley geothermal assets.

Leases in Which the Company is a Lessor

The table below presents lease income recognized as a lessor:

	Year Ended December 31,		
	2025	2024	2023
	(Dollars in thousands)		
Lease income relating to lease payments of operating leases	$ 569,120	$ 553,348	$ 542,065

NOTE 22 — SUBSEQUENT EVENTS

Cash Dividend

On February 24, 2026, the Company's Board of Directors declared, approved and authorized payment of a quarterly dividend of $7.3 million ($0.12 per share) to all holders of the Company's issued and outstanding shares of common stock on March 10, 2026, payable on March 24, 2026.

Convertible Senior Notes

As further disclosed under Note 11 to the consolidated financial statements, on or after January 15, 2027 until the close of business on the second scheduled trading day immediately preceding the maturity date, holders of the Convertible Senior Notes may convert all or any portion of their Notes at any time and as a result, the Company expects to present the

Notes under short-term liabilities on the consolidated balance sheet, starting the first quarter of 2026. As of the filing date of this Form 10-K for the fiscal year ended December 31, 2025, no portion of the Notes was converted.

Business Combination - Solar and Storage Facility Purchase Transaction

On January 29, 2026, the Company closed a purchase transaction with Innergex Renewables USA LLC. to acquire a solar and storage facility on the Big Island of Hawaii, for a total cash consideration of $80.5 million (subject to a customary post-closing working capital adjustment to the purchase price) for 100% of the equity interests in the entity holding this asset. The acquired assets include a 30MW solar PV facility paired with a 30MW/120MWh battery energy storage system, which achieved commercial operation in March 2025. All output from the facility is sold under a 25-year fixed price power purchase agreement with HECO.

As a result of the acquisition, the Company expanded its overall storage and solar generation capacity and expects to improve the profitability of the purchased assets through cost reduction and synergies. The Company will account for the transaction under ASC 805, Business Combinations. The Company is still evaluating the accounting related to the purchase transaction, including the purchase price allocation, and therefore, such allocation is not provided herewith. The Company expects to consolidate the acquired assets in its consolidated financial statements starting from the transaction close date.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

We maintain disclosure controls and procedures that are designed to provide reasonable assurance that information required to be disclosed by us in reports that we file or submit under the Securities Exchange Act of 1934, as amended (the "Exchange Act") is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms, and that such information is accumulated and communicated to our management, including our CEO (principal executive officer) and CFO (principal financial officer), as appropriate, to allow for timely decisions regarding required disclosure. In designing and evaluating the disclosure controls and procedures, management recognizes that any controls and procedures, no matter how well designed and operated, can provide only reasonable assurance of achieving the desired control objectives, and management is required to apply its judgment in evaluating the cost-benefit relationship of possible controls and procedures.

As required by SEC Rule 13a-15(e), we carried out an evaluation, under the supervision and with the participation of our management, including our CEO and CFO, of the effectiveness of our disclosure controls and procedures as of December 31, 2025. Based on this evaluation, our CEO and CFO concluded that our disclosure controls and procedures were effective as of December 31, 2025 to provide the reasonable assurance described above.

Changes in Internal Control Over Financial Reporting

There were no changes in our internal control over financial reporting that occurred during the quarter ended December 31, 2025 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Management's Report on Internal Control over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Rule 13a-15(f) of the Exchange Act. Under the supervision and with the participation of our management, including the CEO and the CFO, we carried out an evaluation of the effectiveness of our internal control over financial reporting as of December 31, 2025 using the criteria established in "Internal Control-Integrated Framework" (2013), issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on that evaluation, our management concluded that our internal control over financial reporting was effective as of December 31, 2025.

Our internal control over financial reporting as of December 31, 2025 has been audited by Kesselman & Kesselman, Certified Public Accountants (Isr.), an independent registered public accounting firm and a member of PricewaterhouseCoopers International Limited ("PwC"), as stated in their report which is included under "Item 8—Financial Statements."

ITEM 9B. OTHER INFORMATION

(a) None.

(b) Each of Jessica Woelfel, the General Counsel, Chief Compliance Office and Corporate Secretary, and Ofer Ben Yosef, the Executive Vice President – Energy Storage and Business Development, modified their existing "Rule 10b5-1 trading arrangements" (as defined in Item 408(a) of Regulation S-K), on November 25, 2025 and December 12, 2025, respectively. The modified Rule 10b5-1 trading arrangements provide for the sale of up to, in Ms. Woelfel's case, 11,662 shares underlying equity awards (assuming maximum payouts under outstanding PSUs) until the earlier of May 8, 2026 or the completion of all transactions under her plan, and in Mr. Ben Yosef's case, 23,144 shares underlying equity awards (assuming maximum payouts under outstanding PSUs), until the earlier of December 10, 2027 or the completion of all transactions under his plan. For SEC disclosure purposes, the modifications are considered terminations of these officers' previously disclosed Rule 10b5-1 trading arrangements (adopted by Ms. Woelfel on June 30, 2025 and Mr. Ben Yosef on June 26, 2025, respectively) and adoptions of new Rule 10b5-1 trading arrangements.

Except as described above, during the fiscal quarter ended December 31, 2025, none of our directors or officers adopted or terminated a "Rule 10b5-1 trading arrangement" or "non-Rule 10b5-1 trading arrangement," as each term is defined in Item 408(a) of Regulation S-K.

ITEM 9C. DISCLOSURE REGARDING FOREIGN JURISDICTIONS THAT PREVENT INSPECTIONS

Not applicable.

PART III

ITEM 10. *DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE*

Information required by this item is incorporated herein by reference to our definitive proxy statement for the 2026 annual meeting of stockholders, which is to be filed with the SEC (the "2026 Proxy Statement").

ITEM 11. EXECUTIVE COMPENSATION

Information required by this item is incorporated herein by reference to our 2026 Proxy Statement.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

Information required by this item is incorporated herein by reference to our 2026 Proxy Statement.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

Information required by this item is incorporated herein by reference to our 2026 Proxy Statement.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

Information required by this item is incorporated herein by reference to our 2026 Proxy Statement.

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 below and immediately preceeding the signature page hereto. As in previous filings, pursuant to Item 601(b)(4)(iii)(A) of Regulation S-K, the Company has not filed as exhibits to this annual report on Form 10-K certain long-term debt instruments (including indentures) under which the total amount of securities authorized does not exceed 10% of the total assets of the Company and its subsidiaries on a consolidated basis. The Company agrees to furnish a copy of any such instrument to the SEC upon request.

Exhibit No.	Document
3.1	Fifth Amended and Restated Certificate of Incorporation, incorporated by reference to Exhibit 3.1 of Ormat Technologies, Inc. Current Report on Form 8-K filed with the Securities and Exchange Commission on May 9, 2024.
3.2	Seventh Amended and Restated By-laws of Ormat Technologies, Inc., incorporated by reference to Exhibit 3.1 to Ormat Technologies, Inc.'s Quarterly Report on Form 10-Q filed with the SEC on August 3, 2022.
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	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.
4.3+	Description of Securities Registered under Section 12 of the Securities Exchange Act of 1934, incorporated by reference to Exhibit 4.4 to Ormat Technologies, Inc.'s Annual Report on Form10-K filed with the Securities and Exchange Commission on February 26, 2021.
4.4	Deed of Trust, dated June 25, 2020, by and between Ormat Technologies, Inc. and Mishmeret Trust Services Company Ltd., as trustee, and a Form of Bonds (included in Schedule One to the Deed of Trust), incorporated by reference to Exhibit 4.1 to Ormat Technologies, Inc.'s Current Report on Form 8-K filed with the Securities and Exchange Commission on July 1, 2020.

4.5 Indenture, dated June 27, 2022, between Ormat Technologies, Inc. and U.S. Bank Trust Company, National Association, incorporated by reference to Exhibit 4.1 to Ormat Technologies, Inc.'s Current Report on Form 8-K filed with the Securities and Exchange Commission on June 27, 2022.

4.6 Form of 2.50% Senior Convertible Note due 2027 (included in Exhibit 4.5).

4.7 First Supplemental Indenture, dated July 15, 2024, between Ormat Technologies, Inc. and U.S. Bank Trust Company, National Association, as trustee, incorporated by reference to Exhibit 4.2 to Ormat Technologies, Inc.'s Current Report on Form 8-K filed with the Securities and Exchange Commission on July 18, 2024.

4.8 Form of Additional 2.50% Senior Convertible Note due 2027, incorporated by reference to Exhibit 4.3 to Ormat Technologies, Inc.'s Current Report on Form 8-K filed with the Securities and Exchange Commission on July 18, 2024.

10.1 Agreement for Purchase of Membership Interests in ORPD LLC, dated February 5, 2015, by and between Ormat Nevada Inc. and Northleaf Geothermal Holdings 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.

10.2 Agreement for Purchase of Membership Interests in ORNI 37 LLC, dated 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.

10.3 Amended and Restated Limited Liability Company Agreement of Opal Geo LLC, dated 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.

10.4 Equity Contribution Agreement, dated 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.

10.5* 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.

10.6* Form of Restricted Stock Unit Grant Notice and Terms and Conditions (Executive Officers) to Ormat Technologies, Inc.'s Amended and Restated 2018 Incentive Compensation Plan, incorporated by reference to Exhibit 10.5 to Ormat Technologies, Inc.'s Quarterly Report on Form 10-Q filed with the Securities and Exchange Commission on August 8, 2018.

10.7* Form of Restricted Stock Unit Grant Notice and Terms and Conditions (Directors) to Ormat Technologies, Inc.'s Amended and Restated 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 1, 2019.

10.8* Form of Stock Appreciation Right Grant Notice and Terms and Conditions (Directors) to Ormat Technologies, Inc.'s Amended and Restated 2018 Incentive Compensation Plan, 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 1, 2019.

10.9* 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.

10.10 Third Amended and Restated Power Purchase Agreement for Olkaria III Geothermal Plants, dated November 26, 2014, between OrPower 4 Inc. and The Kenya Power and Lighting Company Limited, incorporated by reference to Exhibit 10.34 to Ormat Technologies, Inc.'s Annual Report on Form 10-K filed with the Securities and Exchange Commission on February 26, 2021.

10.11 Amendment of the Third Amended and Restated Power Purchase Agreement and Termination of Amended and Restated Olkaria III Project Security Agreement, dated October 30, 2015, between The Kenya Power and Lighting Company Limited and OrPower 4 Inc., incorporated by reference to Exhibit 10.35 to Ormat Technologies, Inc.'s Annual Report on Form 10-K filed with the Securities and Exchange Commission on February 26, 2021.

10.12 Second Amendment of the Third Amended and Restated Power Purchase Agreement, dated December 20, 2016, between The Kenya Power and Lighting Company Limited and OrPower 4 Inc., incorporated by reference to Exhibit 10.36 to Ormat Technologies, Inc.'s Annual Report on Form 10-K filed with the Securities and Exchange Commission on February 26, 2021.

10.13 Third Amendment of the Third Amended and Restated Power Purchase Agreement, dated February 19, 2021, between The Kenya Power and Lighting Company PLC and OrPower 4 Inc., incorporated by reference to Exhibit 10.37 to Ormat Technologies, Inc.'s Annual Report on Form 10-K filed with the Securities and Exchange Commission on February 25, 2022.

10.14 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.

10.15 Finance Agreement, dated 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.

10.16 Amendment No. 1 to the Finance Agreement, dated 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.

10.17 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.

10.18 First Addendum to Loan Agreement, dated March 25, 2019, by and among Ormat Technologies, Inc. and Migdal Insurance Company Ltd., Migdal 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 May 8, 2019.

10.19 Second Addendum to Loan Agreement, dated April 13, 2020, between and among Ormat Technologies, Inc. and Migdal Insurance Company Ltd., Migdal Makefet Pension and Provident Funds Ltd. And Yozma Pension Fund of Self-Employed Ltd., 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 August 6, 2020.

10.20 Finance Agreement, dated April 30, 2018 between Geotérmica 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.

10.21 Amendment to Finance Agreement, dated October 17, 2018 between Geotérmica 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* Amended and Restated Employment Agreement, dated July 2, 2020, between Ormat Technologies, Inc., Ormat Systems, Ltd. and Doron Blachar, incorporated by reference to Exhibit 10.1 and to Ormat Technologies, Inc.'s Current Report on Form 8-K filed with the Securities and Exchange Commission on July 6, 2020.

10.23 Agreement for Purchase of Membership Interests, dated May 21, 2021, by and between TG Geothermal Portfolio, LLC and Deer Holdings, LLC, incorporated by reference to Exhibit 10.63 to Ormat Technologies, Inc.'s Annual Report on Form 10-K filed with the Securities and Exchange Commission on February 25, 2022.

10.24 Form of Capped Call Confirmation, 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 June 27, 2022.

10.25* Employment Agreement, dated May 10, 2020, between Ormat Systems Ltd and Assaf Ginzburg, 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 May 11, 2020.

10.26* Employment Agreement, dated April 1, 2020, between Ormat Systems Ltd and Ofer Ben Yosef, incorporated by reference to Exhibit 10.5 to Ormat's Technologies, Inc.'s Quarterly Report on Form 10-Q filed with the Securities and Exchange Commission on May 4, 2022.

10.27* Employment Agreement dated February 21, 2023 between Ormat Technologies, Inc. and Jessica Woelfel, incorporated by reference to Exhibit 10.42 to Ormat Technologies, Inc.'s Annual Report on Form 10-K filed with the Securities and Exchange Commission on February 24, 2023.

10.28* Employment Agreement, dated June 4, 2025, between Ormat Technologies, Inc. and Aron John Willis, 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 August 7, 2025.

10.29* Ormat Technologies, Inc. Severance Plan, incorporated by reference to Exhibit 10.43 to Ormat Technologies, Inc.'s Annual Report on Form 10-K filed with the Securities and Exchange Commission on February 24, 2023.

10.30* Form of Notification Letter under Ormat Technologies, Inc. Change in Control Severance Plan 43, incorporated by reference to Exhibit C to Exhibit 10.43 to Ormat Technologies, Inc.'s Annual Report on Form 10-K filed with the Securities and Exchange Commission on February 24, 2023.

10.31*† Old form of Performance Stock Unit Grant Notice and Terms and Conditions (Executive Officers) (TSR or MW Performance Target, Three-Year Vesting) under Ormat Technologies, Inc.'s 2018 Amended and Restated Incentive Compensation Plan, incorporated by reference to Exhibit 10.43 to Ormat Technologies, Inc.'s Annual Report on Form 10-K filed with the Securities and Exchange Commission on February 23, 2024.

10.32* Form of Restricted Stock Unit Grant Notice and Terms and Conditions (Executive Officers, Three-Year Vesting) under Ormat Technologies, Inc.'s 2018 Amended and Restated Incentive Compensation Plan, incorporated by reference to Exhibit 10.45 to Ormat Technologies, Inc.'s Annual Report on Form 10-K filed with the Securities and Exchange Commission on February 23, 2024.

10.33†^	Membership Interest Purchase Agreement, dated October 23, 2023, between Snow Wolf Holdings LLC and Enel Green Power North America, Inc. and Enel Kansas, LLC, Enel Geothermal, LLC, EGP Nevada Power, LLC, Stillwater Woods Hill Holdings, LLC, Enel Surprise Valley, LLC, and Enel Cove Fort II, LLC, incorporated by reference to Exhibit 10.46 to Ormat Technologies, Inc.'s Annual Report on Form 10-K filed with the Securities and Exchange Commission on February 23, 2024.
10.34*	Ormat Technologies, Inc. Second Amended and Restated 2018 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 and Exchange Commission on May 9, 2024.
19.1	Ormat Technologies, Inc. Insider Trading Policy, incorporated by reference to Exhibit 19.1 to Ormat Technologies, Inc.'s Annual Report on Form 10-K filed with the Securities and Exchange Commission on February 27, 2025.
21.1	Subsidiaries of Ormat Technologies, Inc., incorporated by reference to Exhibit 21.1 to the Company's Annual Report on Form 10-K filed with the Securities and Exchange Commission on February 25, 2022.
23.1+	Consent of Kesselman & Kesselman, Certified Public Accountants (Isr.), a member firm of PricewaterhouseCoopers International Limited, 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.
97.1	Policy Relating to Recovery of Erroneously Awarded Compensation, incorporated by reference to Exhibit 97.1+ to Ormat Technologies, Inc.'s Annual Report on Form 10-K filed with the Securities and Exchange Commission on February 23, 2024.
101.INS+	Inline XBRL Instance Document.
101.SCH+	Inline XBRL Taxonomy Extension Schema Document.
101.CAL+	Inline XBRL Taxonomy Extension Calculation Linkbase Document.
101.DEF+	Inline XBRL Taxonomy Extension Definition Linkbase Document.
101.LAB+	Inline XBRL Taxonomy Extension Label Linkbase Document.
101.PRE+	Inline 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.

^ Schedules to this exhibit have been omitted pursuant to Item 601(a)(5) of Regulation S-K.

† Certain confidential information contained in this document has been redacted in accordance with Item 601(b)(10)(iv) of Regulation S-K.

\+ Filed herewith.

\# Furnished herewith.

ITEM 16. ***FORM 10-K SUMMARY***

None.

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/ Doron Blachar

Name: Doron Blachar

Title: Chief Executive Officer

Date: February 26, 2026

POWER OF ATTORNEY

KNOW ALL PERSONS BY THESE PRESENTS, that each person whose signature appears below constitutes and appoints Doron Blachar and Assaf Ginzburg, jointly and severally, his or her attorneys-in-fact, each with the power of substitution, for him or her in any and all capacities, to sign any amendments to this Annual Report on Form 10-K, and to file the same, with exhibits thereto and other documents in connection therewith, with the Securities and Exchange Commission, hereby ratifying and confirming all that each of said attorneys-in-fact, or his substitute or substitutes, may do or cause to be done by virtue hereof.

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 and on the dates indicated on February 26, 2026.

Signature	Capacity	Date
/s/ Doron Blachar Doron Blachar	Chief Executive Officer (Principal Executive Officer)	February 26, 2026
/s/ Assaf Ginzburg Assaf Ginzburg	Chief Financial Officer (Principal Financial Officer and Principal Accounting Officer)	February 26, 2026
/s/ Isaac Angel Isaac Angel	Chairman of the Board of Directors	February 26, 2026
/s/Ravit Barniv Ravit Barniv	Director	February 26, 2026
/s/Karin Corfee Karin Corfee	Director	February 26, 2026
/s/ David Granot David Granot	Director	February 26, 2026
/s/ Michal Marom Michal Marom	Director	February 26, 2026
/s/ Dafna Sharir Dafna Sharir	Director	February 26, 2026
/s/ Stanley B. Stern Stanley B. Stern	Director	February 26, 2026
/s/ Byron Wong Byron Wong	Director	February 26, 2026

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-3 (No. 333-283733) and Form S-8 (Nos. 333-224752, 333-265432 and 333-279325) of Ormat Technologies, Inc. of our report dated February 26, 2026 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

February 26, 2026

Exhibit 31.1

CERTIFICATION OF PRINCIPAL EXECUTIVE OFFICER PURSUANT TO SECURITIES EXCHANGE ACT RULES 13a-14(a) AND 15(d)-14(a), AS ADOPTED 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: Chief Executive Officer

Date: February 26, 2026

Exhibit 31.2

CERTIFICATION OF PRINCIPAL FINANCIAL OFFICER PURSUANT TO SECURITIES EXCHANGE ACT RULES 13a-14(a) AND 15(d)-14(a), AS ADOPTED PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Assaf Ginzburg, 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/ Assaf Ginzburg
Name: Assaf Ginzburg
Title: Chief Financial Officer

Date: February 26, 2026

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, 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, to the best of my knowledge, the Annual Report of Ormat Technologies, Inc. on Form 10-K for the year ended December 31, 2025 fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended, 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: Chief Executive Officer

Date: February 26, 2026

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, Assaf Ginzburg, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of my knowledge, that the Annual Report of Ormat Technologies, Inc. on Form 10-K for the year ended December 31, 2025 fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended, 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/ Assaf Ginzburg
Name: Assaf Ginzburg
Title: Chief Financial Officer

Date: February 26, 2026

Ormat's Board of Directors and Executive Management Team

CORPORATE INFORMATION

BOARD OF DIRECTORS

ISAAC ANGEL
Chairman of the board, Former CEO of Ormat

RAVIT BARNIV
Director, Former CEO of Netvision Communications

KARIN CORFEE
Director, Founder and CEO of KC Strategies

DAVID GRANOT
Director, Former CEO of the First International Bank of Israel Ltd.

MICHAL MAROM
Director, Co-Founder and Former CFO of Linkury Ltd.

DAFNA SHARIR
Director, Consultant

STANLEY B. STERN
Lead Independent Director Founder and Managing Partner of Alnitak Capital

BYRON G. WONG
Director, Consultant

SENIOR LEADERSHIP

DORON BLACHAR
Chief Executive Officer

ASSAF GINZBURG
Chief Financial Officer

JESSICA WOELFEL
General Counsel, Chief Compliance Officer, and Corporate Secretary

OFER BEN YOSEF
Executive Vice President—Energy Storage and Business Development

ARON WILLIS
Executive Vice President—Electricity Segment

LIZA TAVORI
Executive Vice President—Human Resources

ELAD ZALKIN
SVP of Projects, Planning & Control, Business Excellence

NIRIT GRUSHKO
SVP of Engineering, R&D Innovation and QEHS

DANIEL MOELK
SVP of Resource, Drilling and EGS

ANNUAL MEETING

The annual meeting of stockholders will be held virtually on June 2, 2026, at 9:00 a.m. EDT. A formal notice of the meeting and proxy materials will be available to each shareholder at https://edge.media-server.com/mmc/p/p3grfokd and will be mailed to any shareholder who requests a printed copy.

STOCK LISTINGS

Ticker: ORA

The New York Stock Exchange

Tel Aviv Stock Exchange

TRANSFER AGENT

Stockholders wishing to update their address, transfer ownership of stock certificates, report lost certificates, or inquire regarding other stock registration matters should contact:

Equiniti Trust Company, LLC
P.O. Box 500
Newark, NJ 07101

CONTACT INFORMATION

Information regarding Ormat Technologies, Inc. is available on our website: www.ormat.com.

Smadar Lavi

VP Head of IR and ESG Planning & Reporting
775-356-9029 (ext. 65726)

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