ASX RELEASE

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Supplemental Disclosure Information

Karoon Energy Limited (ASX: KAR) is releasing the attached Supplemental Disclosure Information document that includes information in relation to its business, results of operations, its financial condition and its subsidiaries, as well as certain risk factors. The Supplemental Disclosure Information has been provided to prospective investors in the proposed offering of an aggregate principal amount of US$400 million in Second-Priority Senior Secured Notes (Notes) by its wholly-owned subsidiary Karoon USA Finance Inc announced earlier today.

Neither this announcement nor the Supplemental Disclosure Information constitute an offer to sell, or the solicitation of any offer to buy, any Notes or other securities. Any offer of Notes will be made only by means of a private offering memorandum. The proposed offer and sale of Notes will not be registered under the US Securities Act of 1933 (US Securities Act) or the securities laws of Australia or any other jurisdiction. Any Notes to be offered may not be offered or sold in the United States without registration under the US Securities Act or unless offered and sold pursuant to an applicable exemption from such registration requirements.

This announcement was authorised by the CEO and Managing Director of Karoon Energy Ltd.

FOR FURTHER INFORMATION ON THIS RELEASE, PLEASE CONTACT

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ABOUT KAROON ENERGY LTD

Karoon Energy Ltd. is an international oil and gas exploration and production company with assets in Brazil, the United States of America and Australia and is an ASX listed company.

Karoon's vision is to be a leading, independent international energy company that adapts to a dynamic world in an entrepreneurial and innovative way. Karoon's purpose is to provide energy safely, reliably and responsibly, creating lasting benefits for all its stakeholders.

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FORWARD-LOOKING STATEMENTS

This offering memorandum includes forward-looking statements within the meaning of United States securities laws. Forward-looking statements involve known and unknown risks, uncertainties and other factors that are in some cases beyond our control. These forward-looking statements include, but are not limited to, all statements other than statements of historical facts contained in this offering memorandum, including, without limitation, those regarding our future financial position and results of operations, our strategy, plans, objectives, goals and targets and future developments or trends in the markets where we participate or are seeking to participate. Some of these statements can be identified by terms and phrases such as "anticipate," "should," "likely," "foresee," "believe," "estimate," "expect," "intend," "continue," "could," "may," "plan," "project," "predict," "will," and similar expressions and include references to assumptions that we believe are reasonable as of the date of this offering memorandum and relate to our future prospects, developments and business strategies.

Many factors could cause our actual results, performance or achievements to be materially different from any future results, performance or achievements that may be expressed or implied by such forward-looking statements. Factors that could cause our actual results to differ materially from those expressed or implied in such forward-looking statements, include, but are not limited to:

- declines in oil and gas prices;
- lower than expected production or additional costs and liabilities due to a range of production risks;
- our dependence on facilities and infrastructure owned and/or operated by third parties, including our dependence of our Brazilian production on a single floating production, storage and offloading facility owned by Altera & Ocyan;
- risks associated with our joint venture and farm-in arrangements;
- inherent technical and geological uncertainty of our oil and gas reserve and resource estimates;
- risks related to completed or potential acquisitions;
- inflationary pressures;
- uncertainty and negative impacts on the economy and energy and capital markets caused by the Russian invasion of Ukraine, tensions in the Taiwan Strait and in the Middle East or any other geopolitical events;
- political risks in Brazil and the United States;
- our ability to replace our existing reserves;
- the highly competitive nature of the oil and gas industry;
- new technologies posing risks of obsolescence to our current exploration and drilling methods;
- concentration on two assets of our production, revenue and cash flow from operating activities;
- increasing attention to environmental, social and governance ("ESG") matters and risks related to ESG aspirations, targets and disclosures;

- our concentrated oil and gas customer base;
- effects of alternative sources of energy on the demand for fossil fuels;
- substantial costs if we fail to ensure the safety of our employees and contractors;
- operational risk and intensive capital expenditure requirements of offshore oil operations;
- the adequacy of our insurance arrangements to cover losses arising from our operations;
- loss of key personnel or a shortage of skilled and semi-skilled labor;
- cyber-security risks and other similar threats;
- outbreak of contagious diseases;
- extensive laws and regulations of the oil and gas industry, including drilling laws;
- our dependence on exploration and production licenses;
- costs of compliance with environmental laws and future removal and environmental restoration costs;
- laws regulating greenhouse gas emissions;
- anti-corruption, anti-bribery, anti-money laundering, sanctions and similar laws;
- tax liabilities;
- litigation, arbitration and regulatory action;
- other risks associated with our financial arrangements and the Notes; and
- other factors referred to in "Risk factors" and elsewhere in this offering memorandum.

We caution that the foregoing list of important factors is not exhaustive. Forward-looking statements are based upon management's good faith assumptions relating to the financial, market, regulatory and other relevant environments that will exist and affect our business and operations in the future. We cannot give investors any assurance that the assumptions upon which management based its forward-looking statements will prove to be correct, or that our business and operations will not be affected in any substantial manner by other factors not currently foreseeable by management or beyond our control.

Accordingly, investors are strongly cautioned not to place undue reliance on any forward-looking statement, particularly in light of the significant volatility, uncertainty and disruption caused by the war between Ukraine and Russia, the ongoing regional conflict in the Middle East, and ongoing tensions between China and the United States and its allies, and each of their associated impacts on global fuel prices, global supply chains and economic growth. These forward-looking statements speak only as of the date of this offering memorandum. We undertake no obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or otherwise. The foregoing factors that could cause our actual results to differ materially from those contemplated in any forward-looking statement included in this offering memorandum should not be construed as exhaustive. You should also read, among other things, the risks and uncertainties described in "Risk factors" and in the documents that we refer to in "Available information." All forward-looking statements are qualified by these cautionary statements.

CREDIT RATINGS

There are references in this offering memorandum to credit ratings. Credit ratings are for distribution only to a person (a) who is not a "retail client" within the meaning of section 761G of the Corporations Act and is also a sophisticated investor, professional investor or other investor in respect of whom disclosure is not required under Part 6D.2 or 7.9 of the Corporations Act, and (b) who is otherwise permitted to receive credit ratings in accordance with applicable law in any jurisdiction in which the person may be located. Anyone who is not such a person is not entitled to receive this offering memorandum and any person who receives this offering memorandum is advised that they must not distribute it to any person who is not entitled to receive it.

A credit rating is not a recommendation to buy, sell or hold securities. There is no assurance that any rating will remain in effect for a given period of time or that any rating will not be revised or withdrawn entirely by a rating agency in the future if in its judgment circumstances warrant such revision or withdrawal. Ratings may be changed, withdrawn or suspended at any time. The rating of each credit rating agency should be evaluated independently of any other rating. We are under no obligation to update information regarding such ratings should they change over time.

AVAILABLE INFORMATION

Neither the Issuer nor any of the Guarantors are subject to the information and reporting requirements of the Exchange Act. While any Notes remain outstanding, we will during any period in which we are not subject to Section 13 or 15(d) of the Exchange Act, or are exempt from reporting pursuant to Rule 12g3-2(b) under the Exchange Act, make available to any "qualified institutional buyer," or QIB, who holds any Notes and any prospective purchaser of a Note who is a QIB designated by such holder of such Note, upon the request of such holder or prospective purchaser, the information required to be provided to such holder or prospective purchaser by Rule 144A(d)(4) under the Securities Act. We file annual reports and half-year reports with the Australian Securities Exchange ("ASX"). You may obtain copies of the documents filed with the ASX from its website at www.asx.com.au.

In addition, copies of such documents can be obtained from the website of the SGX-ST at www.sgx.com. The SGX-ST assumes no responsibility for the correctness of any of the statements made or opinions expressed or reports contained in any such document.

None of the information on a website referred to herein is incorporated by reference herein or otherwise deemed to be a part of this offering memorandum. Any references to websites are for informational purposes only.

FINANCIAL INFORMATION PRESENTATION

Starting July 1, 2023, we have changed our financial year from ending on June 30 of each year to ending on December 31 of each year. This aligns our financial year with Brazil's and the United States' tax year as well as other Australian global oil and gas industry peers. As a result of this change, we had a transitional financial year beginning on July 1, 2023 and ending on December 31, 2023. Our current financial year commenced on January 1, 2024 and will end on December 31, 2024.

This offering memorandum includes our audited consolidated financial statements as of and for the transitional financial year ended December 31, 2023 ("TY23"), our audited consolidated financial statements as of and for the years ended June 30, 2023 ("FY23") and June 30, 2022 ("FY22") and our unaudited condensed consolidated financial statements as of and for the half-year ended December 31, 2022 ("HY23"). The audited consolidated financial statements as of and for FY22 include financial information for the year ended June 30, 2021 ("FY21") as a comparative.

Our audited consolidated financial statements included in this offering memorandum have been prepared in accordance with Australian Accounting Standards ("AAS") and other authoritative pronouncements of the Australian Accounting Standards Board ("AASB"). They also comply with International Financial Reporting Standards ("IFRS") issued by the International Accounting Standards Board ("IASB"). Our unaudited condensed consolidated financial statements included in this offering memorandum have been prepared in accordance with Australian Accounting Standards AASB 134 *Interim Financial Reporting* and comply with IAS 34 *Interim Financial Reporting* as issued by the IASB. The unaudited condensed consolidated financial statements as of and for the half-year ended December 31, 2022 have been reviewed by PricewaterhouseCoopers, independent auditors, in accordance with ASRE 2410 *Review of a Financial Report Performed by the Independent Auditor of the Entity* and the PricewaterhouseCoopers review report is included in this offering memorandum. The audited consolidated financial statements as of and for the transitional financial year ended December 31, 2023 and the financial years ended June 30, 2023 and 2022 have been audited by PricewaterhouseCoopers, independent auditors, in accordance with Australian Auditing Standards and the PricewaterhouseCoopers audit reports are included in this offering memorandum.

Investors should note that AAS and IFRS differ from generally accepted accounting principles in the United States ("US GAAP"), and those differences may be material to the financial information contained in this offering memorandum. Investors should consult their own professional advisors for an understanding of the differences between AAS, IFRS and US GAAP and how those differences might affect the financial information contained in this offering memorandum. We have not provided a quantitative or narrative discussion of these differences in this offering memorandum. Certain amounts (including percentage amounts) have been rounded for convenience; as a result, certain figures may not sum to total amounts or equal quotients.

This offering memorandum also includes the audited statements of revenues and direct operating expenses of the assets we acquired an interest in in the Mississippi Canyon Blocks in the US Gulf of Mexico from LLOG Exploration Offshore L.L.C. and LLOG Omega Holdings, L.L.C. (together, "LLOG") on December 21, 2023 (the "Who Dat assets") for each of the two years in the period ended December 31, 2023.

The audited statements of revenues and direct operating expenses included in this offering memorandum have been prepared in accordance with US GAAP. As these statements only presented revenues and direct operating expenses, we would not have needed to make any material changes to present these statements in accordance with AAS/IFRS. These statements were audited by Ernst & Young LLP, independent auditors, in accordance with auditing standards generally accepted in the United States of America and the Ernst & Young LLP audit report is included in this offering memorandum. Investors should note that these statements of revenues and direct operating expenses were prepared for the purpose of inclusion in this offering memorandum and are not intended to be a complete presentation of the revenues and expenses of the Who Dat assets.

UNAUDITED PRO FORMA COMBINED FINANCIAL INFORMATION

This offering memorandum includes certain unaudited pro forma combined financial information that has been prepared for the purpose of illustrating the impact the acquisition of the Who Dat assets might have had on our consolidated statement of profit and loss for the year ended December 31, 2023. The unaudited pro forma combined statement of profit or loss for the year ended December 31, 2023 gives effect to the acquisition of the Who Dat assets and related financing transactions as if they had occurred on January 1, 2023.

The assumptions and estimates underlying the unaudited pro forma adjustments applied to the historical financial information of Karoon Energy and of the Who Dat assets to present the unaudited pro forma financial information are described in the notes to the unaudited pro forma combined financial information.

The unaudited pro forma combined financial information should be read together with our historical financial statements and the audited statements of revenues and direct operating expenses of the Who Dat assets, both of which are included elsewhere herein.

The unaudited pro forma combined financial information has been presented for illustrative purposes only and is not intended to represent or be indicative of the results of operations or the financial position of Karoon Energy that would have been recorded had the acquisition of the Who Dat assets been completed as of the dates presented and should not be taken as representative of the future results of operations or financial position of Karoon Energy.

Investors should note that the unaudited pro forma combined financial information included in this offering memorandum does not purport to comply with the requirements of Article 11 of Regulation S-X under the Securities Act or the American Institute of Certified Public Accountants' published guidelines for the preparation and presentation of pro forma financial information. Neither the underlying pro forma adjustments nor the resulting pro forma financial information have been audited or reviewed in accordance with AAS. Accordingly, the unaudited pro forma combined financial information presented in this offering memorandum should not be relied upon by investors to provide the same quality of information as information that has been subject to an audit or review by an independent auditor. **Investors are cautioned not to place undue reliance on the pro forma combined financial information contained in this offering memorandum**.

NON-IFRS FINANCIAL MEASURES

We use a number of operational measures and non-IFRS financial measures to assess the financial and operational performance of our business. These non-IFRS measures do not have standardized meanings prescribed by AAS or IFRS or by other authoritative pronouncements issued by the AASB or IFRS as issued by IASB, and therefore may not be comparable with other similarly titled measures presented by other entities, nor should these be interpreted as an alternative to other financial measures determined in accordance with AAS or IFRS. We believe these operational measures and non-IFRS measures provide useful information about our business and our management considers these measures in analyzing our operating and financial performance.

The non-IFRS measures we use include:

- EBITDA is earnings before interest, tax, depreciation, depletion and amortization (but including the depreciation and interest on our FPSO right of use asset).

- Interest cover ratio is our underlying EBITDA divided by our net interest expense.

- Gearing ratio is our net debt divided by net debt plus equity.

- Leverage ratio is our net debt divided by our underlying EBITDA.

- Net debt/(cash) is our total borrowings (excluding transaction costs) less cash and cash equivalents.

- Net interest expense is our interest expense minus our interest income.

- PV-10 measures are the period-end present values of the estimated future cash inflows from the relevant reserves category less future development and production costs and discounted at 10% to reflect the timing of future cash flows, using pricing assumptions in effect at the end of the period. PV-10 figures presented in this offering memorandum should not be construed as an estimate of the fair market value of the properties. See also "Cautionary note regarding PV-10 values."

- Underlying EBITDA is our EBITDA as adjusted for several non-cash items and other expenses that we believe are not representative of our underlying performance.

These operational and non-IFRS financial measures should not be considered in isolation from, or as a substitute for, financial information prepared in accordance with IFRS. See "Management's discussion and analysis of financial condition and results of operations – Overview – Key operational measures and non-IFRS financial measures" for information about why we consider these metrics useful and a discussion of the material limitations of these measures, as well as a reconciliation of these measures to the most directly comparable financial measure prepared in accordance with IFRS.

EXCHANGE RATES AND CONVERSION FACTORS

Currency of presentation and exchange rates

The consolidated financial statements of Karoon Energy, including the financial information included in this offering memorandum, are presented in United States dollars. In this offering memorandum, references to "A$" are to Australian dollars; references to "R$" are to Brazilian Real, references to "US$" or "U.S. dollars" are to United States dollars, and references to "S$" are to Singapore dollars.

This offering memorandum includes references to Brazilian real amounts, which have been translated into US$ amounts. Unless otherwise stated, we have translated R$ into US$ at our transitional financial year end rate as of December 31, 2023 of R$1 = US$0.2034.

The A$ is convertible into US$ at freely floating exchange rates and there are currently no restrictions on the flow of A$ between Australia and the United States, except as described in "Australian exchange controls" above.

Conversion factors

We have used a conversion factor of 6 mcf equaling 1 boe to convert from gas to oil equivalent.

CAUTIONARY NOTE REGARDING INDUSTRY AND THIRD-PARTY DATA

This offering memorandum contains market data and statistics, third party estimates and other information (including industry forecasts and projections). Market data used throughout this offering memorandum have been obtained from independent experts, independent industry publications and other publicly available information, including information in the report attached hereto as Annex B which was prepared by Wood Mackenzie (see "Independent consultant reports").

The industry and market data contained in this offering memorandum is based on estimates and assumptions that we believe to be reasonable. Although we believe the third-party market data estimates and projections and our own internally generated data, which we used in preparing management estimates, to be reliable, we have not independently verified such information or the underlying assumptions relied upon therein, and we cannot guarantee or assure you as to its accuracy or completeness or as to the accuracy or completeness of any underlying assumptions used in preparing such information.

Investors should note that industry data and statistics are often based on extrapolating from limited data and subject to a range of limitations and possible errors, including errors in data collection and the possibility that relevant data has been omitted. Certain of the data and statistics are based on market research, which itself is based on sampling and subjective judgments by both the researchers and the respondents, including judgments about what types of products and transactions should be included in the relevant market. In addition, the value of comparisons of statistics for different markets is limited by many factors, including that (a) the markets are defined differently, (b) the underlying information was gathered by different methods and (c) different assumptions were applied in compiling the data. As a result, this data is subject to uncertainty and not necessarily reflective of actual market conditions. To the extent the information relates to future events, it is subject to additional risks and uncertainties and may change as a result of various factors as described elsewhere within this offering memorandum. In particular, estimates, forecasts and projections involve risks and uncertainties and are subject to change based on factors discussed in the "Risk factors" section and elsewhere herein.

INDEPENDENT CONSULTANT REPORTS

Information in this offering memorandum includes a summary of a report, dated March 18, 2024, regarding estimates of the reserves, contingent resources and PV-10 future net revenues of Baúna. The report this summary is based on was prepared by our independent expert, AGR Energy Services AS, a firm consisting of independent petroleum engineers, geologists, geophysicists and petrophysicists, who was hired and compensated by us. The summary of this report is included as an annex to this offering memorandum. See "Annex A – Summaries of independent reserve reports."

Information in this offering memorandum includes a summary of a report, dated April 9, 2024, regarding estimates of our share of the reserves, contingent resources and PV-10 future net revenues from the Dome Patrol and Who Dat oil and gas fields. The report this summary is based on was prepared by our independent expert, Netherland, Sewell & Associates, Inc., a firm consisting of independent petroleum engineers, geologists, geophysicists and petrophysicists, who was hired and compensated by us. The summary of this report is included as an annex to this offering memorandum. See "Annex A – Summaries of independent reserve reports."

Information in this offering memorandum regarding the Brazil and US Gulf of Mexico offshore oil and gas industry and other related matters was derived from a report prepared by Wood Mackenzie, dated April 2024, an independent consultancy company specialized in the Brazilian and US oil and gas industry, who was hired and compensated by us. The report is included as an annex to this offering memorandum. See "Annex B – Brazil and US Gulf of Mexico Offshore Market Assessment."

Each of AGR Energy Services AS, Netherland, Sewell & Associates, Inc. and Wood Mackenzie has given and not withdrawn their consent to the inclusion of the summaries of their reports or their report, as applicable, their name and all references to them in this offering memorandum. Each of those reports speaks only as of the dates indicated therein and the independent consultants have no obligation to update such information.

CAUTIONARY NOTE REGARDING RESERVES AND CONTINGENT RESOURCES

This offering memorandum contains data relating to our petroleum reserves and contingent resources.

Unless otherwise stated, estimates of petroleum reserves and contingent resources are as of December 31, 2023. All estimates of petroleum reserves and contingent resources we report are prepared by, or under the supervision of, a qualified petroleum reserves and resources evaluator or evaluators. We prepare our petroleum reserves and continent resources estimates in accordance with the 2018 Petroleum Resources Management System ("PRMS 2018"). PRMS 2018 is sponsored by the Society of Petroleum Engineers. We follow the PRMS 2018 in order to comply with the ASX requirements for petroleum reserve and resource estimates for Australian publicly listed companies. Investors should note, however, that different petroleum reserves and contingent resources employ different assumptions. As a result, because of the impact of such assumptions, identical raw data can produce varying estimates of petroleum reserves and contingent resources. Our methodologies for classifying petroleum reserves and our petroleum reserves classifications vary in certain respects from the methodologies and classifications used by oil and gas companies subject to the reporting obligations of the SEC, including the reporting requirements set out in Regulations S-K and S-X under the Securities Act and related SEC disclosure requirements.

Estimates of petroleum reserves and contingent resources are largely dependent on the interpretation of data obtained from drilling, testing and production. These interpretations may prove to be incorrect over time and require revision. Estimates of proved reserves that may be developed and/or produced in the future are frequently based upon volumetric calculations and by analogy to similar types of reservoirs or geologic formations rather than upon actual production or injection history. Subsequent evaluation of the same reservoirs or geologic formations based upon actual production or injection rates and pressure information may result in revisions to the estimated proved or proved plus probable reserves. An estimate of petroleum reserves and contingent resources is based in part on a field's long-term development plan, and these estimates are classified or adjusted and re-classified as contingent where a long-term development plan has not been finalized or is not up-to-date or where the development plan is found to not be commercial. The estimation of petroleum reserves and contingent resources involves a significant degree of judgment by our management, engineers and technical personnel. These estimates are subject to various uncertainties, including those relating to the physical characteristics of oil and gas fields, changes in oil and gas prices and variable rock and fluid properties. These uncertainties are difficult to estimate and, as a result, actual production capacity may be materially different from current estimates of petroleum reserves and contingent resources. No assurance can be given that the petroleum reserves and contingent resources presented in this offering memorandum will be recovered or utilized at the levels presented. We have included in this offering memorandum estimates of our proved, or 1P, reserves, our proved plus probable, or 2P, reserves, our proved plus probable plus possible, or 3P, reserves and our probable, or 2C, contingent resources. Readers should carefully consider the definitions of these categories set out elsewhere in this offering memorandum and understand the degree of uncertainty attached to each category. Particular caution should be applied to our 3P reserve estimates and our 2C contingent resource estimates. 3P reserves includes estimated quantities of hydrocarbons the extraction of which we do not consider probable. Contingent resources are less certain than reserves. Our contingent resources are estimates of hydrocarbon quantities that are not recoverable under current conditions and may never become recoverable. These are contingent resources that are potentially recoverable but not yet considered mature enough for commercial development due to technological or business hurdles. For contingent resources to move into the reserves category, the key conditions, or contingencies, that prevented commercial development must be clarified and removed. We would not be permitted to disclose our 3P reserves or 2C contingent resources in an SEC registration statement.

We engage independent experts as required to assist with the integrity of our reserves and contingent resources estimates. We engaged independent experts AGR Energy Services AS, or AGR, and Netherland, Sewell & Associates, Inc., or NSAI, to deliver independent reserves reports for Baúna and for the Dome Patrol and Who Dat oil and gas fields, respectively, as of December 31, 2023. Summaries of those reports have been included in this offering memorandum in Annex A. As of December 31, 2023, AGR's estimate of our 2P reserves in Baúna was approximately 2.5% lower than our estimate of 2P reserves. We have relied upon NSAI's independent reserves report in preparing our estimates of our share of reserves and contingent resources from the Who Dat assets, and any differences between our estimates and the estimates presented by NSAI relate to differences in oil price forecasts. As of December 31, 2023, NSAI's estimate of our share of 2P reserves from the Who Dat assets was approximately 0.6% lower than our estimate of 2P reserves. We believe that the differences between our reserves estimates and those of AGR and NSAI reflect differences in reasonable professional judgment in interpreting data and applying assumptions and are not material.

For a discussion of how we estimate our petroleum reserves and contingent resources, including how we define "proved reserves," "probable reserves," "possible reserves" and "contingent resources" and some differences between our reserves reporting system and the SEC regulations, see "Reserves and contingent resources."

CAUTIONARY NOTE REGARDING PV-10 VALUES

We have included in this offering memorandum PV-10 values of our 1P, 2P and 3P reserves as calculated by our independent experts, AGR and NSAI. In preparing these PV-10 values, our independent experts have used their own estimates of our 1P, 2P and 3P reserves, which are different from what we estimate our reserves to be. For more information about our reserves estimates, see "Cautionary note regarding reserves and contingent resources" and "Reserves and contingent resources."

PV-10 values are non-IFRS financial measures and represent the period-end present values of the estimated future cash inflows from the relevant reserves category less future development and production costs and discounted at 10% to reflect the timing of future cash flows. For more information about the inputs used by AGR and NSAI in preparing these PV-10 values, see their reports included in this offering memorandum in Annex A. AGR's and NSAI's PV-10 estimates do not use SEC pricing assumptions, and therefore cannot be reconciled to any IFRS or US GAAP measure, such as the standardized measure of discounted future net cash flows, which is the most directly comparable US GAAP financial measure to PV-10 values that are discounted using SEC pricing assumptions. Furthermore, US GAAP does not provide a measure of estimated future net cash flows for reserves other than proved reserves. Because PV-10 estimates of 2P and 3P reserves are more uncertain than PV-10 estimates of 1P reserves, but have not been adjusted for risk due to that uncertainty, they may not be comparable with each other. Nonetheless, we believe that PV-10 estimates for reserves categories other than proved reserves and using the pricing assumptions employed by our independent experts present useful information for investors about the future net cash flows of our reserves in the absence of a comparable IFRS or US GAAP measure such as the standardized measure of discounted future net cash flows.

Generally, PV-10, even when calculated using SEC pricing, is not equal to, or a substitute for, the US GAAP financial measure of standardized measure of discounted future net cash flows. The 1P, 2P and 3P reserve PV-10 values presented in this offering memorandum do not purport to present the fair value of our hydrocarbon reserves. However, our management believes that the presentation of PV-10 is useful because it presents the relative monetary significance of our properties regardless of tax structure. Further, investors may utilize the measure as a basis for comparison of the relative size and value of our reserves to other companies. We use this measure when assessing the potential return on investment related to our hydrocarbon gas properties. In addition, investors should be cautioned that estimates of PV-10 for 2P and 3P reserves, as well as the underlying volumetric estimates, are inherently more uncertain of being recovered and realized than comparable measures for proved reserves, and that the uncertainty for possible reserves is even more significant. For further discussion of the risks and uncertainties inherent in reserves and contingent resource estimations, see "Risk factors – Risks relating to our industry and operations – Our oil and gas reserve and resource estimates are subject to inherent technical and geological uncertainty and may be revised downwards as a result of lower commodity prices or changed regulation that may result in previously booked reserves no longer being commercially recoverable."

GLOSSARY

This Glossary sets forth the meanings of certain abbreviations and technical terms used in this offering memorandum. Certain financial terms are defined above under "Non-IFRS financial measures." Additional information regarding petroleum reserves definitions is contained in "Reserves and contingent resources."

A$ or AUD	Australian dollars.
AASB	Australian Accounting Standards Board.
amplitude	Amplitude is a measurement of the amount of energy transferred by a wave. Amplitude variation with offset is one of the main technologies of searching for oil and gas reservoirs.
ANP	Agencia Nacional do Petróleo, Gás Natural e Biocombustíveis (the Brazilian National Agency of Petroleum, Natural Gas and Biofuels).
API	The American Petroleum Institute gravity, or API gravity, is a measure of how heavy or light a petroleum liquid is compared to water.
ASX	The Australian Securities Exchange, operated by ASX Limited.
barrel or bbl	Barrel of oil, inclusive of condensate. A quantity of 42 United States gallons; equivalent to approximately 159 litres.
Baúna	Concession BM-S-40 containing the producing Baúna, Piracaba and Patola light oil fields in Brazil.
block	A license or concession area. It may be almost any size or shape, although usually part of a grid pattern.
bopd	Barrels of oil per day.
BP	BP Plc or BP Plc and its subsidiaries, as the context may require.
carbon neutral	Refers to having a balance between emitting and offsetting greenhouse gas emissions, achieved through acquiring carbon offsets in respect to our Scope 1 and 2 GHG emissions.
cash breakeven price	We calculate our cash breakeven price as the sum of our operating costs, royalties and other government take, transportation costs, other expenses (excluding depreciation and amortization – non oil and gas assets, share-based payments expense and realized losses on cash flow hedges) and our sustaining capital expenditure divided by our sales volumes in the period.
CNPE	Brazilian National Council for Energy Policy, a body subordinated to the President of Brazil and responsible for establishing the public policies related to the energy industry.

contingent resources	Those quantities of hydrocarbons estimated, as of a given date, to be potentially recoverable from known accumulations by application of development projects, but which are not currently considered to be commercially recoverable (as evaluation of the accumulation is insufficient to clearly assess commerciality). • 2C – Denotes best (P50) estimate of contingent resources.
CO_2e	Carbon dioxide equivalent.
discovery well	The first successful well on a new prospect.
EBITDA	Earnings before Interest, Taxes, Depreciation, and Amortization.
ESG	Environmental, social, and governance.
exploration	The process of identifying, discovering and testing prospective hydrocarbon regions and structures, mainly by interpreting regional and specific geochemical, geological, geophysical survey data and drilling.
FID	Final Investment Decision.
field	An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature or stratigraphic condition. The field name refers to the surface area although it may refer to both the surface and underground productive formation.
fixed remuneration	Relates to fixed cash remuneration consisting of base salary and superannuation contributions/pension contributions.
floating production system uptime	We calculate the uptime rate for the Who Dat floating production system by dividing the number of days with production by the number of days in the given time period, excluding scheduled downtime.
floating production, storage and offloading facility efficiency rate	We calculate our efficiency rate for the Baúna floating production, storage and offloading facility as actual production divided by our reservoir production forecast, limited to 100%.
FPS	Floating Production System.
FPSO	Floating production, storage and off-loading facility.
GHG	Greenhouse gas.
GST	Goods and Services Tax in Australia.
HSSE	Health, safety, security and environment.
IBAMA	Brazilian Institute of Environment and Renewable Natural Resources.

m	Million.
Mgal	Million of gallons (1,000,000 gallons).
MMbbl	Millions of barrels (1,000,000 barrels).
net revenue interest or NRI	Our working interest net of royalties charged by the American Office of Natural Resources Revenue and third-party royalties.
net working interest or NWI	Our working interest prior to any royalties being deducted.
net zero	Refers to the reduction of Scope 1 and 2 GHG emissions as far as possible and offsetting the residual greenhouse gas emissions through investment in carbon removal or sequestration initiatives equal or greater to the residual greenhouse gas amount.
OMS	Operating Management System.
performance rights	Performance rights issued under Karoon Energy's performance rights plan.
Petrobras	Petróleo Brasileiro SA.
prospect	A geological or geophysical anomaly that has been surveyed and defined to the degree that its configuration is fairly well established, and on which further exploration such as drilling can be recommended.
reserves	Those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions. • 1P – Denotes low (P90) estimate of reserves. • 2P – Denotes best (P50) estimate of reserves. • 3P – Denotes high (P10) estimate of reserves.
reservoir	A porous and permeable rock formation to store and transmit fluids such as hydrocarbons and water.
SWST	Shell Western Supply and Trading Limited (a member of the Royal Dutch Shell Plc group).
SOFR	Secured Overnight Financing Rate.
tCO2e	Tonnes of carbon dioxide equivalent.
US$	United States dollars.
Williams	Williams Companies, Inc. or Williams Companies, Inc and its subsidiaries, as the context may require.

Investing in the Notes offered by this offering memorandum involves risk. You should consider carefully the risks described below before you decide to purchase the Notes. The risks described below are not an exhaustive list of the risks facing us or that may develop in the future. There may be additional risks not described below, not presently known to us, or that we currently consider to be immaterial that could turn out to be material in the future. If any of the following risks actually occurs, our business, financial position and results of operations are likely to suffer. In this case, the trading price of the Notes could decline, and you may lose all or part of your investment.

Risks relating to our industry and operations

Significant declines in oil and gas prices may materially affect our financial condition and results of operations, cash flows, access to the capital markets and available borrowings under our RBL facility.

Our business generates substantially all of its revenue by producing and selling oil and, to a lesser extent, natural gas. We sell all of our oil production from Baúna under a marketing arrangement with Shell Western Supply and Trading Limited, or SWST, which is a member of the Royal Dutch Shell Plc group. We sell our share of crude oil from Who Dat to BP Products North America Inc., a member of the BP Plc group, under a month-to-month evergreen crude oil purchase agreement. We sell our share of natural gas from Who Dat on a six-month seasonal contract basis to BP Energy Company, also a member of the BP Plc group, under a gas purchase contract, and we sell our share of natural gas liquids under a life-of-asset sales agreement at prices linked to the Mont Belvieu index as adjusted for the cost of transportation and fractionation to Williams Field Services, a U.S. based natural gas infrastructure provider. Sales under these contracts are either at spot prices or at prices set by pricing formulas that incorporate market-based pricing indices. As a result, our revenues, cash flows, and results of operations depend on the market prices of oil and natural gas, which are subject to fluctuations due to market conditions, supply and demand, global economic growth, geopolitical events, environmental regulations, the availability of transport and shipping infrastructure, and other factors beyond our control. These factors include:

- levels of global economic activity which is the main driver of demand for oil and gas;
- the level of global oil and gas supply;
- expectations regarding future supply and demand;
- the availability and capacity of transportation, storage, and refining infrastructure;
- the actions and policies of the Organization of the Petroleum Exporting Countries (“OPEC”) and other major oil and gas producing countries and regions, and their impact on production quotas, output levels, and exports, including any price wars between principal oil producing countries, such as the recent price wars between Russia, Saudi Arabia and the United States, which resulted in significant fluctuations in oil prices;
- the political, economic, and social conditions and conflicts in oil and gas producing and consuming regions, and the potential for disruptions, sanctions, wars, terrorism, cyberattacks, or other events that could affect production, transportation, or trade of oil and gas, including Russia’s ongoing war in Ukraine, hostilities in the Middle East, including the conflict between Israel and Hamas and military operations between Israel, Iran and Iran’s proxies, political instability in Venezuela or the United States or Yemeni rebel assaults on ships crossing the Red Sea, where a majority of the world’s seaborne crude oil flows through;
- the level of oil and gas exploration and development;

- the development and adoption of new technologies, alternative energy sources, or energy efficiency measures that could reduce the demand for or increase the supply of oil and gas;

- the enactment, implementation, or enforcement of new or existing environmental, climate change, carbon emissions, health and safety, tax or other laws and regulations that could affect the production, transportation, or consumption of oil and gas, or impose additional costs, liabilities, or restrictions on our operations; and

- natural disasters, including circumstantial effects of climate change and meteorological phenomena, such as storms and hurricanes, which especially affect the Gulf of Mexico, pandemics, accidents, or other events that could affect the availability or operation of our facilities, equipment, personnel, or suppliers, including third party logistics and transportation.

If the prices of oil and gas decline significantly or for a prolonged period, our revenues, cash flows and results of operations could be adversely and materially affected and we may not be able to recover our costs of production, exploration, and development. Lower oil and gas prices may result in reduced production if the costs of producing from any of our operations no longer generates a sufficient return and we decide to halt our development and exploration plans or suspend or cease production. Because our reserve and resource estimates are estimates of quantities that we can commercially produce, lower oil and gas prices may result in us reducing our reserve and resource estimates and may result in asset impairments and such reductions may affect our ability to access funding. See "– Our oil and gas reserve and resource estimates are subject to inherent technical and geological uncertainty and may be revised downwards as a result of lower commodity prices or changed regulation that may result in previously booked reserves and no longer being commercially recoverable" and "– Interim and annual reviews of our reserves and resources may result in reserve and resource write-downs, us recognizing impairments in the carrying value of our assets or changing our development plans."

Reduced cash flows as a result of lower oil and gas prices may adversely affect our ability to service our debt. Lower oil and gas prices may also reduce the amount available for us to borrow because the borrowing limit under our RBL facility is based in part on our estimated proved and probable reserves. See "Description of other financing arrangements."

We enter into hedging transactions for oil and gas prices from time to time in accordance with our hedging policy in order to mitigate the effect of price fluctuations and as required by our RBL facility. See "Management's discussion and analysis of financial condition and results of operations—Overview—Key factors affecting our results—Oil and gas prices." However, we will remain exposed to price fluctuations for the unhedged portion of our production, our hedges will expose us to the risk of default from our hedge counterparties and if prices rise, we may recognize losses on our hedges that offset the gains from higher prices on the unhedged portion of our production.

Our production may be lower than expected or we may incur additional costs and liabilities due to a range of production risks.

Oil and gas production is subject to numerous risks that may result in production being interrupted, lower than expected or ceasing earlier than expected or resulting in us incurring additional costs or liabilities. These risks include:

- risks relating to the unpredictable nature of oil and gas reservoirs, including premature decline or total failure of reservoirs, invasion of water into producing formations, encountering unexpected formations or pressures, low permeability of reservoirs and unusual or unexpected rock formations and abnormal geological pressures, all of which may lead to us not being able to conduct drilling operations or drilling operations not resulting in commercially feasible oil and gas production;

- operational risks such as the failure of wellhead, gathering lines, flowlines, pumps or other processing infrastructure or equipment, failure of or damage to transportation infrastructure, blowouts and other uncontrollable flows of hydrocarbons or well fluids, explosions, fires, contamination of oil and gas, oil and other chemical spills, shortages of skilled labor and equipment, long lead and times for certain equipment or contract services, pollution and other environmental risks; and

- risks associated with conducting production, development and exploration drilling operations in offshore locations, including extreme weather conditions (including hurricanes and cyclones, the frequency and severity of which could be exacerbated by climate change), which can interrupt operations and damage equipment and infrastructure, potentially severely, as well as the hazards inherent in marine operations, such as marine vessels capsizing, sinking or colliding and the risks of helicopter operations, and the risk of oil spills in marine environments.

If we are forced to shut-in production, we may incur greater costs to bring associated production back online. Cost increases necessary to bring the associated wells back online may be significant enough that it may not be economic to bring such wells back online at low commodity price levels, which may lead to decreases in our proved reserve estimates. See "– Interim and annual reviews of our reserves and resources may result in reserve and resource write-downs, us recognizing impairments in the carrying value of our assets or changing our development plans" for further details regarding the risks associated with decreases in our proved reserve estimates. If we are able to bring wells back online, there is no assurance that such wells will be as productive following recommencement as they were prior to being shut-in. If any of these risks occur, our production could be interrupted, resulting in our production and revenues being substantially lower than what we expect and could adversely affect our financial condition and results of operations.

All of our Brazilian production is processed through a single floating production, storage and offloading facility, *Cidade de Itajaí*, and all of our US Gulf of Mexico production is processed through a single floating production system. Any disruption to the operation of these facilities could have a significant impact on our production. For further details regarding historical disruptions to our operations at *Cidade de Itajaí*, see "– Our Brazilian production depends on a single floating production, storage and offloading facility owned by Altera & Ocyan."

Unplanned partial or full shutdowns could adversely impact our financial condition and results of operations if such shutdowns require substantial costs to remediate or continue for an extended period of time, particularly if production interruptions coincide with a period of relatively higher prices. The impact of production interruptions in a high price environment may be exacerbated by losses on our hedges.

The risk of an interruption to our production may be exacerbated by our reliance on third party operators and infrastructure and the concentration of our operations in a small number of fields in two geographical regions. See "– Our Brazilian production depends on a single floating production, storage and offloading facility owned by Altera & Ocyan", "– Our joint venture and farm-in arrangements may expose us to various risks and decrease our ability to manage risks" and "– Our success depends, in part, on our ability and that of the operator of our non-operated assets to develop new oil and gas projects, the failure of which could prevent us from realizing profits, or result in the total or partial loss of our investment."

In addition, in Brazil, exploration, development and production activities are usually described in detail in plans and work programs prepared by the concessionaire/contractor in accordance with the relevant ANP regulations and such plans and programs are assessed and approved by the ANP prior to the commencement of activities comprised therein. If any delays or interruptions cause a material change of scope of an approved plan or program, a revised version must be submitted to the ANP for approval, describing any amendments thereto. Discussions with the ANP concerning plans and work programs may be time-consuming and may impact the relevant operations. In addition, our failure to timely present or have plans and programs approved by the ANP, as well as any failure to duly comply with the requirements of such plans and programs, may lead to the imposition of fines by the ANP and, in the worst-case scenario, to the termination of the relevant concession contract (subject to an administrative proceeding). See "Regulatory overview – ANP."

Our Brazilian production depends on a single floating production, storage and offloading facility owned by Altera & Ocyan.

As noted above, all of our Brazilian production is processed through a single floating production, storage and offloading facility, *Cidade de Itajaí*. The *Cidade de Itajaí* is owned by Altera & Ocyan, a joint venture formed between infrastructure service providers Altera and Ocyan, and we have a charter contract that expires in 2026 (with two one-year extension options by mutual agreement). The *Cidade de Itajaí* has a number of systems that lack redundancy, meaning that their failure could result in an interruption of production until they have been repaired. A disruption to the operation of the *Cidade de Itajaí* could result in an interruption to production from our Baúna assets, which would have an immediate impact on our cash flow from operations and profitability, as well as potentially requiring additional expenditure to remedy defects. For example, on March 28, 2023, production on the *Cidade de Itajaí* was shut down after a hydrocarbon leak from pipework within the gas flare system. While the leak was isolated and repaired, we and the floating production, storage and offloading facility operator, Altera & Ocyan, decided to undertake a more comprehensive inspection of the facility's pipework, resulting in a shutdown that extended to 42 days. In November 2023, operational issues in the facility's gas lift dehydration unit led to the formation of hydrates in two wells. We subsequently discovered a mechanical blockage in the gas lift valve of one our wells, SPS-88, which impeded production rates, pending an intervention that we anticipate be completed by the third quarter of 2024 at a cost of approximately US$20-30 million.

Under our charter, we depend on Altera & Ocyan and its personnel to maintain the *Cidade de Itajaí* facility. Altera & Ocyan is also responsible for any replacement costs or costs associated with repairs. We have been working with Altera & Ocyan to address a range of operational issues with the *Cidade de Itajaí* where we have sought improvements, including adding redundancy to a number of key systems. We have also notified Altera & Ocyan of a number of non-compliances for which we believe we are entitled to receive contractual penalties. While we believe that we and Altera & Ocyan are working constructively to resolve the remaining operational issues, a failure by Altera & Ocyan to address the remaining issues would result in an elevated risk of production interruptions. If we are unable to satisfactorily resolve the outstanding contractual items, it may not be possible or desirable to exercise the two one-year options to extend the floating production, storage and offloading facility charter contract beyond its current expiry date in February 2026 (which would require us to provide notice a year in advance) or negotiate an extension beyond February 2028.

If we were required to replace the *Cidade de Itajaí* with a different floating production, storage and offloading facility, we anticipate that we would incur significant additional expenses and our production from Baúna would be interrupted, potentially for an extended period if we were unable to secure a replacement floating production, storage and offloading facility within the timeframe we require.

We also have an operating services contract with OOG-TKP, an affiliate of marine transportation company Teekay, for a range of services on the *Cidade de Itajaí*, including crewing the vessel, managing the handling, processing and storage of crude oil, water injection, gas lift, gas export and transferring crude oil to shuttle tankers. A number of these services are critical to the operation of the facility, and a failure to perform these services with due skill and care could result in production interruptions and damage to the facilities. We have limited ability to directly supervise the performance of these services.

We depend on facilities and infrastructure owned and/or operated by third parties, which may expose us to operational, financial and legal risks that are beyond our control.

In addition to the *Cidade de Itajaí*, our oil and gas production activities depend on a range of other third party facilities and infrastructure. We have used third-party offshore drilling rigs to support our Brazilian exploration and development activities, in particular the *Noble Developer* semi-submersible offshore drilling rig, which is owned and operated by Noble, and we expect to engage third party offshore drilling contractors in the future, including for the SPS-88 well intervention. We also use third party operators in our Brazilian operations to, among other things, provide hydrocarbon spill response equipment, service support vessels for the floating production, storage and offloading facility, including remotely operated vehicles and helicopters, which are (in some cases) required to satisfy the facility's operating license requirements. We depend on ships with dynamic positioning capability to offload our production from the *Cidade de Itajaí*. Dynamic positioning ships are able to maintain their position while offloading using onboard propulsion without the need to anchor or moor. These services may be scarce and may not be readily available at the times and places required or at favorable rates. As a result of our marketing arrangement with Shell, we are able to access Shell's fleet of vessels to offload our production. If Shell's fleet becomes unavailable to us as a result of the termination of our marketing arrangement or otherwise, there may be limited alternatives available to us in Brazilian waters. As a result, offloading our production may become more expensive and/or not immediately available.

The US Gulf of Mexico operations in which we have multiple minority joint venture interests are operated by LLOG. All of our US Gulf of Mexico production is currently processed through the floating production system from three producing areas. LLOG is responsible for managing the day-to-day operations, including the drilling, development, completion, production, maintenance and decommissioning of the wells, subsea infrastructure and facilities, including the floating production system. We rely on the operator to perform these functions in a safe, efficient, compliant and profitable manner, and to provide us with accurate and timely information and accounting. See also "Business – Our production and exploration assets – United States of America."

We do not have direct control over the availability, reliability, capacity, cost, maintenance, IT systems or physical security, operation or compliance of any of the floating production, storage and offloading facility in Brazil or the floating production system in the US Gulf of Mexico and other third-party services, and we may incur liabilities, including liability with respect to government authorities or other third parties, or losses as a result of their failure, disruption, damage, delay, breach of contract, force majeure, environmental incidents, regulatory actions, disputes or other events affecting them or their operators. Any indemnities that we may receive from such parties may be inadequate or difficult to enforce.

Where we do not act as operator of the acreage in which we have an interest, such as in the US Gulf of Mexico, we depend on the operator to conduct exploration and development activities. We may have limited influence or recourse over the operator's decisions, actions or omissions, which may not align with our interests, objectives or expectations. The success and timing of exploration and development activities on properties operated by others depends upon a number of factors that could be largely outside of our control, including but not limited to the timing and amount of certain capital expenditures; the availability of suitable offshore drilling rigs, drilling equipment, support vessels, production and transportation infrastructure and qualified operating personnel; the operator's expertise and financial resources; and approval of other participants in drilling wells.

In addition, we have limited control over the maintenance of safety and environmental standards of the US Gulf of Mexico operations. The operator may incur higher than expected capital or operating expenditures, fail to comply with applicable laws and regulations, encounter operational or technical difficulties, delay or cancel planned activities, or engage in disputes or litigation with us or other co-owners. Any of these events could adversely affect our share of production, revenues, costs, reserves, resources, liabilities and reputation.

LLOG, which operates the Who Dat assets, also relies on a range of third party contractors, including for transportation and logistics services. Oil production from the Who Dat field is transported to the mainland United States via the Mars pipeline, which is a common carrier pipeline operated by a subsidiary of Shell, and gas is transported via the Canyon Chief and Transco pipelines into the Mobile Bay Gas Plant, all operated by Williams. We depend on these operators to maintain and operate this infrastructure safely and effectively. Some of this infrastructure is decades old and may be more prone to failure than more modern infrastructure. If there is a failure at any of these facilities, production may be interrupted from Who Dat until alternative arrangements can be made, which may require the joint venture to construct new equipment and infrastructure in order to access alternative facilities. For example, from May 1, 2024 to May 21, 2024, the Williams Mobile Bay Gas Processing facility will undergo maintenance, which will require us to temporarily utilize an alternative route to market for natural gas at an additional cost of $0.69/mcf and $0.05/gallon NGL costs incurring approximately US$250,000 of additional costs.

Our joint venture and farm-in arrangements may expose us to various risks and decrease our ability to manage risks.

We are a minority, non-operating joint venturer in our US Gulf of Mexico operations. It is likely that we will engage in additional joint ventures in the future, either through farming in to new operations or farming out our existing or future operations, such as Neon in Brazil, if developed. The use of joint ventures and associated farm-in/farm-out arrangements is common in the oil and gas exploration, development and production industry and serves to mitigate the risk and associated cost of exploration, development, production and operational failure. However, disputes or failure of agreement or alignment with joint venture partners, including in relation to operations, budgets, development plans or joint venture audits, our failure as an operator of joint venture or farm-in arrangements or the failure of third party joint venture or farm-in operators or parties, could have a material effect on our business. These arrangements can also decrease our ability to manage risks and costs, particularly where we are not the operator. We could have limited information on, influence over and control of the behavior and performance of these operations. In addition, misconduct, fraud, bankruptcy, noncompliance with applicable laws and regulations or improper activities by or on behalf of one or more of our joint venture or farm-in partners could have a significant negative impact on our business and reputation.

The failure of joint venture or farm-in partners to meet their commitments and share of costs and liabilities can result in increased costs to us thereby adversely impacting our financial condition and results of operations. Additionally, there is a risk that our joint venture partners may at any time have economic, business or legal interests or goals that are inconsistent with those of the joint venture or us. If this occurs, our business, financial condition and results of operations may be adversely impacted, and we may lose our investment in such partnerships.

Disagreements and divergent interests with joint venture partners could lead to disputes, which may be disruptive to the joint venture, as well as being expensive, time consuming and may lead to adverse results. See "– Risks relating to our regulatory, tax and legal environment – Our business subjects us to potential liability from litigation, arbitration and regulatory action." The offshore operating agreements governing the operation of the US Gulf of Mexico joint ventures in which we have interests all provide for certain decisions to be made by majority vote. Because we are a minority working interest holder in those fields, the other working interest partners may make those decisions in ways with which we disagree and we will be bound by the result. The offshore operating agreements also provide the operator with significant scope to make operational decisions, including in decisions in the case of an emergency that may involve substantial expenditure, without the advance approval of the other working interest parties. Our dependence on the operator and other working interest owners and our limited ability to influence operations and certain associated costs of properties operated by others could prevent the realization of anticipated results in drilling or acquisition activities. See also "Business – Our production and exploration assets – United States of America."

Our oil and gas reserve and resource estimates are subject to inherent technical and geological uncertainty and may be revised downwards as a result of lower commodity prices or changed regulation that may result in previously booked reserves no longer being commercially recoverable.

We have prepared reserves and resources estimates consistent with PRMS 2018, which is sponsored by, among others, the SPE, the World Petroleum Council, the American Association of Petroleum Geologists and the Society of Petroleum Evaluation Engineers, and we follow the PRMS 2018 in order to comply with ASX requirements for Australian publicly listed companies. Changes to the PRMS 2018 or any other applicable guidelines or requirements, may also impact our calculation of petroleum reserves and contingent resources estimates. The PRMS 2018 was last updated and released in July 2018, and a key clarification was the requirement for 1P reserves to demonstrate positive economics based on estimated entitlement forecast quantities and associated cash flow. Future changes to PRMS 2018 may result in reductions to our estimates of our petroleum reserves and contingent resources. See also "Cautionary note regarding reserves and contingent resources."

Under the PRMS 2018 framework, reserves are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions. Reserves must satisfy four criteria: discovered, recoverable, commercial and remaining (as of the evaluations effective date) based on the development project(s) applied. Contingent resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations, by application of development project(s) not currently considered commercial owing to one or more contingencies, such as projects for which there are currently no viable markets, where commercial recovery is dependent upon technology under development, where evaluation of the accumulation is insufficient to clearly assess commerciality, where the development plan is not approved, or where regulator or social acceptance issues may exist.

Reserves and resources quantities are inherently uncertain and may not materialize. Significant uncertainties are inherent in the reservoir geology, the seismic and well data available and other factors, such as project development, revenues, taxes, development expenditures, quantities of recoverable oil and gas reserves and resources and operating costs, together with relevant commodity prices and evolving regulatory requirements. The process of estimating oil and gas reserves and resources is complex. Estimated reserve quantities are based upon interpretations of geological and geophysical models and assessments of the technical feasibility and commercial viability of producing the reserves. These assessments require assumptions to be made regarding future development and production costs, commodity prices, exchange rates and fiscal regimes. Any significant inaccuracies in these interpretations or assumptions could materially affect our estimated quantities and present value of our reserves. In addition, the estimates of reserves may change from period to period as the economic assumptions used to estimate the reserves could change from period to period, and as additional geological and engineering data is generated during the course of operations. In addition, we may adjust estimates of reserves to reflect production history, results of exploration and development, prevailing oil and gas prices and other factors, many of which are beyond our control. Uncertainties are heightened for undeveloped reserves, which are expected to be recovered from new wells on undrilled acreage or from existing wells that require major expenditure for recompletion. As of December 31, 2023, our reserves were mainly developed reserves but we may have significant undeveloped reserves in the future as we expand our business.

Uncertainty in relation to reserves and resources is often expressed as a range of reserves and/or resources levels with associated probabilities. We have recorded reserves and resources in connection with fields of varying maturity levels. During the course of exploration, appraisal, development and continuing operations, the increased quantity and sources of data will generally improve the accuracy of the reserves and resources estimates and narrow the range of uncertainty. However, there is always a risk that the reserves actually produced may vary from the predicted reserves estimate, for example tending to the lower end of the volume uncertainty range, in response to poorer reservoir performance than expected or earlier than expected water influx, or other technical or commercial reasons. In some cases, the stated reserves may, during, or at the end of, field-life, vary significantly from the previous estimates, either upwards or downwards for various technical or commercial reasons, which may have an adverse impact on our revenue and ability to meet our contractual commitments.

We have included in this offering memorandum estimates of our proved, or 1P, reserves, our proved plus probable, or 2P, reserves, our proved plus probable plus possible, or 3P, reserves and our probable, or 2C, contingent resources. Readers should carefully consider the definitions of these categories set out elsewhere in this offering memorandum and understand the degree of uncertainty attached to each category. Particular caution should be applied to our 3P reserve estimates and our 2C contingent resource estimates. 3P reserves include estimated quantities of hydrocarbons, the extraction of which we do not consider probable. Our 2C contingent resources are estimates of hydrocarbon quantities that are not recoverable under current conditions and may never become recoverable. We would not be permitted to disclose our 3P reserves or 2C contingent resources in an SEC registration statement. No assurance can be given that the reserves and resources presented in this offering memorandum will be developed, produced or recovered at the levels presented or that the volumes will be maintained given ongoing evaluation work. Our properties may also be susceptible to hydrocarbon drainage from production by other operators on adjacent properties.

The estimates that we have made at a point of time are also subject to revision as a result of subsequent developments, including changes global commodity prices and the regulatory framework in which we operate, which may adversely impact the commercial recoverability of our reserves. The prices at which we expect to be able to sell the oil and gas when we extract it are critical to our reserves estimates. An extended or substantial decline in oil and gas prices or demand for oil and gas or expectation of such decline may mean that previously booked reserves and resources may no longer be regarded as recoverable, leading to a reduction in reserve and resource estimates.

Similarly, changes to the regulatory framework in which we operate or enhanced environmental scrutiny could result in the extraction of previously booked reserves and resources no longer being commercially viable. These changes include:

- the introduction or increase of a carbon price mechanism or any other mechanism that raises the cost of carbon or greenhouse gas emissions. See also "– Risks relating to our regulatory, tax and legal environment – Laws regulating greenhouse gas emissions could adversely affect the cost, manner and feasibility of doing business and demand for the oil and gas that we produce;"

- any increase in regulatory compliance costs or the imposition of additional restrictions or conditions on our operations, including new requirements for environmental approval or licenses, emission limits, or decommissioning obligations (including security arrangements); and

- a reduction in support or increased opposition to the extraction of hydrocarbons from our stakeholders, such as governments, our communities, customers, suppliers, lenders, investors or activists, that may affect our reputation, social license to operate, contractual arrangements or existing legal rights.

Any of these factors may result in a downwards revision of our reserve and resource estimates. Downward revisions of our contingent and prospective resources resulting from study reviews and/or access to additional data, changes in commodity prices or changes in regulation may result in lower than expected production levels, which could materially and adversely impact our business, financial condition or operational results. See also "– Interim and annual reviews of our reserves and resources may result in reserve and resource write-downs, us recognizing impairments in the carrying value of our assets or changing our development plans."

The present value of future net cash flows of our proved reserves and the associated PV-10 calculation are not necessarily the same as the current market value of our estimated oil and gas reserves.

You should not assume that any present value of future net cash flows from our proved reserves represents the market value of our estimated oil and gas reserves. We base the estimated discounted future net cash flows from our proved reserves at December 31, 2023 on assumptions about price and costs. See also "Cautionary note regarding PV-10 values" and "Annex A – Summaries of independent reserve reports" for more information about how these PV-10s were calculated. Actual future prices and costs may be materially higher or lower. Further, actual future net revenues are affected by factors such as among other things:

- the amount and timing of capital expenditures and decommissioning costs;

- the rate and timing of production;

- changes in governmental legislation, regulations or taxation;

- volume, pricing and duration of our oil and gas hedging contracts;

- supply of and demand for oil and gas;

- actual prices we receive for oil and natural gas; and

- our actual operating costs in producing oil and natural gas.

The timing of both our production and our incurrence of expenses in connection with the development and production of oil and natural gas properties affects the timing of actual future net cash flows from reserves, and, thus, their actual present value. In addition, the 10% discount factor that we use to calculate the net present value of future net revenues and cash flows may not necessarily be the most appropriate discount factor based on our cost of capital in effect from time to time and the risks associated with our business and the oil and gas industry in general.

Interim and annual reviews of our reserves and resources may result in reserve and resource write-downs, us recognizing impairments in the carrying value of our assets or changing our development plans.

We undertake regular reviews of our reserves and resources, including as part of preparing and finalizing our interim and full-year financial statements. We may revise our reserves and resources downwards for a range of factors as described in "– Our oil and gas reserve and resource estimates are subject to inherent technical and geological uncertainty and may be revised downwards as a result of lower commodity prices or changed regulation that may result in previously booked reserves no longer being commercially recoverable."

We recognize an impairment loss when the carrying amount of an asset exceeds its estimated recoverable amount, which is the greater of its fair value less costs of disposal and its value in use. Value in use is primarily based on the asset's estimated future cash flows, discounted to their present value, while fair value is based on discounted future cash flows plus other relevant factors such as value attributable to additional resource and exploration opportunities beyond reserves based on production plans. Any required write-downs or impairments could materially affect the quantities and present value of our reserves, which could adversely affect our business, results of operations and financial condition.

The expected future cash flow estimate is based on a number of factors, the most important of which are estimates of hydrocarbon reserves and resources, future production profiles, commodity prices, operating costs, foreign exchange rates and carbon price and abatement cost assumptions. Accordingly, if oil and/or gas prices fluctuate, decline or we expect oil and/or gas prices to decline or fluctuate, our estimate of future cash flows may decrease and, as a result we may estimate a lower fair value less costs of disposal and/or value in use.

We also undertake impairment testing of our capitalized exploration and development expenses. We capitalize the costs of successful exploration wells, acquiring interests in new exploration assets and appraisal costs relating to determining feasibility. When the technical and commercial feasibility of an undeveloped field has been demonstrated, we capitalize the costs of development. A write-down of resources associated with a field in development may result in a write-down of the associated capitalized exploration and development expenses. It may also result in us altering our development and production plans in ways that adversely affect the timing and volume of our expected future production. See also "Management's discussion and analysis of financial condition and results of operations – Critical accounting policies – Impairment of oil and gas assets."

Risks related to completed or potential acquisitions may adversely affect our business, including risks related to our ability to realize all of the anticipated benefits of our acquisitions and our ability to integrate our acquisitions successfully.

Our strategy includes seeking to grow our business through acquisitions of additional assets or businesses, such as our recently completed acquisition of interests in US Gulf of Mexico assets from LLOG, and we regularly evaluate acquisition opportunities and engage in negotiations with third parties with respect to new opportunities.

Acquisitions involve numerous risks, including:

- inadequate due diligence leading to our failure to properly understand and value an acquired asset, including failing to identify material risks;

- changes in our future capital and operating expenditure obligations, which may impact our funding requirements;

- incurring liabilities resulting from previous activities of operators and joint venture partners, or from any areas not disclosed or uncovered during due diligence processes;

- the costs and management time required to integrate new businesses into our operations and execute growth identified at the time of entering a transaction may not be realized post-completion;

- risks associated with the entry into any new jurisdiction for which we have limited experience;

- operating a larger organization;

- coordinating geographically disparate organizations, systems and facilities;

- diverting management's attention from regular business concerns;

- failing to execute on integration plans and maximize cost savings, including with respect to corporate, technological and administrative functions;

- failing to operate new assets as effectively as previous owners; and

- failing to successfully develop growth projects we acquire.

We conduct a due diligence investigation in connection with any acquisition, and we may rely on employees or third parties we engage as part of the due diligence process to conduct such due diligence investigations. We may also rely on information provided by or on behalf of the seller or third parties we engage, and we may not be able to verify the accuracy, reliability or completeness of such information. For example, we employed several third party advisers to assist us with the due diligence process for the acquisition of interests in our US Gulf of Mexico assets from LLOG. However, the information we obtain in connection with an acquisition may be incomplete, incorrect, inaccurate or misleading. The analysis we and our advisers undertake in connection with an acquisition may result in conclusions and forecasts that are inaccurate or are not realized, whether because of flawed methodology, misinterpretation of data or otherwise. Due to competitive or other pressures, we may need to commit to an acquisition before we have all of the information and analysis we would like. As a result of any of these factors, the actual characteristics and performance of an acquired asset may be materially different than we expect, which may have an adverse impact on our financial position and results of operations.

When we acquire another company, the liabilities (including financial debt, whether assumed or refinanced) of the company acquired may become our liabilities, which may increase our financial leverage and result in changes to other credit metrics, which could adversely impact our credit capacity and credit ratings.

There may be threatened, contemplated, asserted or other claims against the assets we acquire related to environmental, title, regulatory, tax, contract, litigation or other matters of which we are unaware, which could materially and adversely affect our production, revenues and results of operations. We may be successful in obtaining contractual indemnification for preclosing liabilities, including environmental liabilities, but we expect that we will generally acquire interests in properties on an "as is" basis with limited remedies for breaches of representations and warranties. In addition, even if we are able to obtain such indemnification from the sellers, these indemnification obligations usually expire over time and could potentially expose us to non-indemnified liabilities, which could materially adversely affect our production, revenues and results of operations.

Our unaudited pro forma combined financial information is for informational purposes only and is not intended to reflect what our actual results would have been had our acquisition of interests in US Gulf of Mexico assets from LLOG occurred on January 1, 2023 and may not be a reliable indicator of our future results.

The historical financial statements included in this offering memorandum consist of separate consolidated financial statements of Karoon Energy and the statements of revenues and direct operating expenses of the Who Dat assets. These financial statements were used to create the unaudited pro forma combined financial information included in this offering memorandum under "Selected unaudited pro forma combined financial information." The unaudited pro forma combined financial information is for illustrative purposes only. It does not reflect the costs of any integration activities or transaction-related costs or incremental capital expenditures that may be necessary for us to realize the anticipated benefits from the acquisition. Accordingly, the pro forma combined financial information included in this offering memorandum is not intended to, and does not purport to, represent what our actual results would have been if our acquisition of interests in US Gulf of Mexico assets from LLOG occurred on January 1, 2023, or what our results of operations will be in the future. In addition, such unaudited pro forma combined financial information is based in part on certain assumptions regarding the acquisition that we believe are reasonable and comply with applicable accounting guidance. The assumptions used in preparing the unaudited pro forma combined financial information may not prove to be accurate, and other factors may affect our financial condition and results of operations. Actual results may differ materially from the assumptions used to present the accompanying unaudited pro forma combined financial information. See also "Unaudited pro forma combined financial information."

The unaudited pro forma combined financial information does not include all the information and disclosures required by IFRS for a complete set of financial statements. The unaudited pro forma combined financial information has been derived from and should be read in conjunction with our consolidated financial statements and the statements of revenues and direct operating expenses and related notes of the acquired assets, as applicable, and the sections titled "Management's discussion and analysis of financial condition and results of operations" included elsewhere in this offering memorandum.

Our success depends, in part, on our ability and that of the operator of our non-operated assets to develop new oil and gas projects, the failure of which could prevent us from realizing profits, or result in the total or partial loss of our investment.

We have a number of assets in the early stages of being evaluated for future exploration or development, including the Neon discovery in Brazil and the Who Dat East, Who Dat South and Who Dat West fields in the US Gulf of Mexico. Exploration and appraisal activities require developers of oil and gas assets to spend significant amounts of capital – in particular to drill exploration and appraisal wells – based on limited geological data. There can be no assurance that our or our joint venture's exploration or appraisal activities will confirm that the identified fields contain sufficient quantities of hydrocarbons in formations amenable to economic extraction to justify development.

Once we, or we and our joint venture partners, decide to develop a field, we will face a range of risks that are common to major project execution. These include the risk that the project may cost more or take longer to complete than we expect or that it may fail to perform as planned, resulting in inadequate returns on our investment or that the market for such products will change during the development phase. The risks in developing major projects include:

- delay in or failure to obtain and maintain the necessary government approvals or changes in the regulatory requirements during the development process;

- failures in design, engineering or construction;
- failures by contractors to perform their obligations, including the delivery of projects or equipment on time and to the necessary specifications;
- procurement issues, including equipment fabrication delays and logistical and sourcing challenges due to disruption in global supply chains, labor shortages, inflation, and geopolitical instability;
- unexpected geological conditions, including as a result of failure to correctly interpret geological data;
- unanticipated increases in costs, including for contractors or equipment;
- adverse weather conditions and natural disasters;
- environmental, health and safety or social license issues; and
- inadequate governance, risk management and decision-making.

Developing major oil and gas projects takes a number of years. During this period, market conditions, including those relating to costs, supply and demand fundamentals, financing conditions, geopolitical conditions (including sanctions) and the status of counterparties (including contractors and off-take partners) may change from those that we have forecasted, and these changes may adversely impact our ability to deliver on our various project objectives, delay the revenue coming from these operations or make a project not economically viable or result in additional unexpected investments. See also "– We depend on facilities and infrastructure owned and/or operated by third parties, which may expose us to operational, financial and legal risks that are beyond our control" and "– We may be unable to access the infrastructure, equipment, goods and services we need to operate our producing assets and develop our growth projects."

In addition to financial losses, poor or failed delivery of major projects could result in damage to our reputation and relationships with our project partners, threats to our social license to operate, reduced workforce prospects and reduced ability to invest in our business.

Any of these events may cause changes to the development plans for our Brazilian assets previously approved by ANP. Any such changes could have a material effect on our expected capital expenditure and the timelines associated with the development of our assets. See the last paragraph of "– Our production may be lower than expected or we may incur additional costs and liabilities due to a range of production risks." for further risks regarding ANP's oversight of exploration and development activities.

We may be unable to access the infrastructure, equipment, goods and services we need to operate our producing assets and develop our growth projects.

We require a range of infrastructure, equipment, goods and services to operate our producing assets and develop our growth projects. Some of these items can be scarce and subject to cyclical availability and may not be readily available at the times and places required. In particular, offshore drilling rigs are in high demand and it can be difficult to secure appropriate rigs at the times required to execute our plans. In addition, there are long lead times for customized items such as wellheads. Periods of particularly high demand, which usually coincide with periods of elevated oil prices, can also result in increased prices for long-lead items, including wellheads, remotely operated vehicles, umbilical systems and pipe and rig leases and increased wages of the crews that operate them. If we or the operators of our joint venture assets are unable to secure drilling rigs at the times we need them, our exploration, appraisal and development plans will not proceed on the schedule we have set, which may cause a delay in our path to productivity for an asset and may require us to change our development plans with ANP with respect to our Brazilian operations.

The marketability of our production depends upon the availability, proximity, operation and capacity of oil and gas gathering systems, pipelines and processing facilities. The lack of availability or capacity of this infrastructure could result in the shut-in of producing wells or delays or discontinuance of development plans for our properties. The disruption of these gathering systems, pipelines and processing facilities due to maintenance and/or weather could negatively impact our ability to market and deliver our products.

High demand for the items we need could drive up prices, increasing our costs, which could have a material adverse effect on our operating income, cash flows and borrowing capacity and may require a reduction in the carrying value of our properties, our planned level of spending for exploration and development and the level of our reserves. Prices for the materials and services we depend on to conduct our business may not be sustained at levels that enable us to operate profitably.

We and our current or future offtakers may also depend on the availability of storage tanks and transportation systems, such as pipeline systems, oil tankers and onshore terminals, which may be subject to capacity constraints and price increases. If we are unable to sell the oil and gas we produce in a timely fashion, or if increased prices for transportation and storage infrastructure reduce the prices we receive for our production, our cash flow and results of operations may be adversely affected.

Our industry and the broader global economy have been experiencing significant inflationary pressures. If these conditions persist, they may impact our ability to procure labor, materials and equipment on a cost-effective basis, or at all, and, as a result, our business, financial position and results of operations could be adversely affected.

Since 2021, we have experienced inflationary pressures resulting in increases in the cost of labor, materials and equipment, including fuel, field services and field equipment, which, in turn, caused our capital expenditures and operating costs to rise. These inflationary pressures have been largely as a result of supply chain disruptions following the COVID-19 pandemic and, more recently, increased geopolitical instability, and the resulting increase in global demand for certain field services and equipment, challenges in the supply of labor and/or labor shortages. While COVID-19-related supply pressures have eased, inflation remains a challenge due to increased activity levels in the oil and gas industry and we may continue to experience supply chain constraints and inflationary pressure on our cost structure in future periods. If inflationary conditions persist or worsen, they could result in increased capital expenditures and operating costs, reduced margins and production delays and adversely impact the timing and results of operations from our major projects. As a result, our business, financial position and results of operations could be adversely affected.

Historically, Brazil has suffered high rates of inflation. The Brazilian federal government has adopted various measures in response to inflation negatively affecting the Brazilian economy. There is no guarantee that the Brazilian economy will not be affected in the future by new inflationary pressures. We are party to various contracts that are adjusted for inflation, and our ability to meet our obligations may thus be adversely materially impacted if inflation were to persist in Brazil. Inflationary pressures may also reduce our ability to access foreign financial markets, affect the ability of counterparties to honor their commitments, and lead to additional government interventions in the Brazilian economy.

The Brazilian Central Bank's Monetary Policy Committee ("COPOM") periodically establishes the SELIC rate, the basic interest rate for the Brazilian banking system, which serves as an important instrument for compliance with inflation targets. The basic interest rate has fluctuated frequently in recent years. COPOM has frequently adjusted the basic interest rate due to economic uncertainties and to achieve the currency stability objectives determined by the monetary authority. On August 4, 2022, the SELIC reached 13.75%, its highest level in five years, after a decision taken by COPOM commenting that the various measures of underlying inflation are above the range compatible with meeting their inflation target. In September 2023, COPOM began reducing the SELIC, which reached 10.75% in its latest update as of March 20, 2024. Increases in the basic interest rate may adversely affect our results of operations, through a reduction in the demand for credit, an increase in funding costs, and an increase in the risk of counterparty defaults.

Our business, financial condition and results of operations may be materially adversely affected by any negative impact on the global economy and energy and capital markets resulting from the Russian invasion of Ukraine, tensions in the Taiwan Strait and in the Middle East or any other geopolitical events.

In February 2022, Russia launched a military invasion of Ukraine. In response, various Western allied countries, including the member states of the European Union, the United Kingdom, the United States and Australia implemented a series of wide-ranging economic sanctions and export controls against Russia, and Russian officials have made a variety of threats against countries that have supported Ukraine. The outcome and the broader consequences of the conflict are unpredictable. In October 2023, armed conflict escalated between Israel and Palestine after an attack on Israel by Hamas and recently there have been military operations between Israel, Iran and Iran's proxies. There is a risk that these events may lead to a wider conflict in the Middle East. In addition, recent years have seen high levels of tension in the Taiwan Strait as a result of indications that China may contemplate military action against Taiwan.

The consequences of these conflicts and any other geopolitical events may negatively impact other regional and global economies, on various sectors, industries and markets for securities and commodities globally. Military conflicts may result in hostile actions outside of the principal sphere of conflict, such as disruption of shipping lanes (including those used for energy transport) and cyber attacks. Any military conflict may also cause regional instability, geopolitical shifts, and could materially adversely affect global trade, currency exchange rates, regional economies and the global economy. The extent and duration of the war in Ukraine or conflicts in the Middle East, the likelihood of future hostilities, the extent, duration and impact of existing and future sanctions, the potential blockade of key trade corridors, other market disruptions and volatility, and the result of any diplomatic negotiations are highly uncertain. These and any related events may impact global energy prices, increase our production costs or lead to project delays, any of which could have a material adverse impact on our business, financial condition and results of operations.

If we are unable to replace our existing reserves due to competition with a range of industry participants with respect to acquiring new reserves and the capital-intensive nature of exploring, developing and acquiring reserves, we may not be able to sustain production over the longer term.

Our longer-term prospects depend on us replacing existing oil and gas reserves as they are depleted through production, from either exploration or acquisition. We have rights to extract or have access to a finite amount of oil and gas reserves, which will be depleted over time. Producing oil and gas reservoirs are generally characterized by declining production rates that vary depending upon reservoir characteristics and other factors. Unless we conduct successful exploration, appraisal and development and exploitation activities or acquire properties containing reserves, our reserves will decline as those reserves are produced. We expect to reach the end of field life for our Baúna reserves by 2031 and 2032 for 1P and 2P reserves, respectively.

Securing new sources of hydrocarbons is a challenging and competitive undertaking. Additionally, the availability of cash and financing to fund acquisitions of new sources of hydrocarbons may be adversely impacted by market conditions. Exploration for oil and gas resources is a high-risk endeavor subject to geological and technological uncertainties and the failure to replace reserves is a risk inherent in our industry. Exploration activity involves the interpretation of seismic and other geological and geophysical data, which does not always successfully predict the presence of commercial quantities of oil and gas. The cost of drilling, completing, and operating wells may be curtailed, and drilling operations may be delayed or canceled as a result of a variety of factors including: unexpected adverse conditions, unexpected drilling conditions, irregularities in pressure or formations, equipment failure or accidents, fire, explosions, blowouts, weather interruptions, miscalculations or accidents, increases in the cost of or shortages or delays in the availability of rigs and equipment leading to the abandonment of the well(s) and a total loss of our investment. Future developments may be affected by unexpected reservoir conditions, which negatively affect recovery factors or flow rates. Our future oil and gas reserves and production, and therefore our cash flows and results of operations, depend on our success in efficiently developing our current reserves and economically discovering or acquiring additional recoverable reserves.

We compete for reserves acquisitions, exploration leases, licenses, concessions and marketing agreements against a wide range of industry participants, many of which have significantly larger financial and other resources than we have. See "– The oil and gas industry is highly competitive." These companies may be able to pay more for exploratory prospects and productive oil and natural gas properties and may be able to define, evaluate, bid for and purchase a greater number of properties and prospects, including operatorships and licenses, than our financial or human resources permit. If we are unsuccessful in discovering or acquiring new resources and developing and producing additional reserves, then we may not meet our long-term goals for growth or sustainability in production, and our future total reserves and production may decline and adversely affect our results of operations and financial position.

The oil and gas industry is highly competitive.

The oil and gas industry is characterized by intense competition among a wide variety of participants, including the major oil companies, government-backed national oil companies, independent oil and gas concerns, individual producers, gas marketers and major pipeline companies. Many of these competitors have significantly greater resources than we have, and some may have favored access to governments and other regulators in certain jurisdictions. Competitors may also have a greater ability to continue drilling activities during periods of low oil and gas prices and to absorb the burden of current and future governmental regulations and taxation.

In addition to competing to acquire additional oil and gas reserves and resources, we compete with other industry participants to hire skilled employees, to retain third party service providers, to procure equipment, to access existing and innovative technologies and to access capital. If we are unable to compete successfully in the future, our future revenues and growth may be diminished or restricted.

Competition may result in us failing to secure resources that we need to operate and expand our business or may result in us having to pay higher prices than we expect, which could increase our costs, delay our projects or result in interruptions to our production.

New technologies may cause our current exploration and drilling methods to become obsolete, and we may not be able to keep pace with technological developments in our industry.

The oil and natural gas industry is subject to rapid and significant advancements in technology, including the introduction of new products and services using new technologies. As competitors use or develop new technologies, we may be placed at a competitive disadvantage, and competitive pressures may force us to implement new technologies at a substantial cost. In addition, competitors may have greater financial, technical and personnel resources that allow them to enjoy technological advantages, and that may, in the future, allow them to implement new technologies before we can. We rely heavily on the use of advanced seismic technology to identify exploitation opportunities and to reduce our geological risk. Seismic technology or other technologies that we may implement in the future may become obsolete. We cannot be certain that we will be able to implement technologies on a timely basis or at a cost that is acceptable to us. If we are unable to maintain technological advancements consistent with industry standards, our business, results of operations and financial condition may be materially adversely affected.

Our production, revenue and cash flow from operating activities are derived from only two main production assets.

We have two main production assets, comprising six operating oil fields; the Báuna asset, which we operate offshore Brazil, and the Who Dat asset, in which we have non-operating interests in the US Gulf of Mexico. We also hold exploration and development acreage adjacent to Báuna and Who Dat. As such, the success and performance of our operations may be disproportionately exposed to the effect of regional conditions such as:

- severe weather, such as hurricanes, winter storms, loop currents, tornadoes and other adverse climatic conditions;
- changes in local laws and regulations affecting our operations (including regulations that may, in certain circumstances, impose strict liability for pollution damage or require posting substantial bonds to address decommissioning costs) and interruption or termination of operations by governmental authorities based on environmental, safety or other considerations;

- local price fluctuations and other regional supply and demand factors, including availability of gathering, pipeline, transportation and storage capacity constraints;

- production delays or decreases in the regions limited potential customers;

- infrastructure capacity and availability of rigs, equipment, oil field services, supplies and labor;

- changes in the status of pipelines that we depend on for transportation of our production to the marketplace; and/or

- changes imposed as a result of litigation or by a new government in Brazil or a new presidential administration or Congress in the United States that may result in added restrictions and delays or prohibitions in offshore oil and gas exploration and production activities, including with respect to leasing, permitting, site development or operation in federal waters or hydraulic fracturing.

Because all or a number of our operating oil and gas fields could experience many of the same conditions at the same time, these conditions may have a relatively greater impact on our results of operations than they might have on other producers who have a larger number of assets across wider geographic areas.

Increasing attention to ESG matters may adversely impact our business and strategic objectives.

In recent years, increasing attention has been given to corporate activities related to ESG matters in public discourse and the investment community. A number of advocacy groups have campaigned for governmental and private action to promote change at public companies related to ESG matters, including through the investment and voting practices of shareholder activists, investment advisers, private fund managers, public pension funds, superannuation funds, sovereign wealth funds, universities and other members of the investing community. These activities include increasing attention and demands for action related to climate change and promoting the transition away from fossil fuel as a primary energy source. A failure to understand and respond to investor or public expectations and standards, which are evolving, could cause us reputational harm and may adversely impact our business and strategic objectives.

In addition, organizations that provide information to investors on corporate governance and related matters have developed ratings processes for evaluating companies on their approach to ESG matters. Such ratings are used by some investors to inform their investment and voting decisions. Also, some stakeholders have been urging lenders to limit funding to companies engaged in practices that are perceived to be detrimental to the environment. Unfavorable ESG ratings and investment community divestment initiatives may lead to negative investor sentiment toward us, which could have a negative impact on our access to and costs of capital. See also "– Risks relating to our financial arrangements – If we are unable to raise funds on favorable terms, including in order to fund our growth projects and any future acquisitions and refinance our existing debt, our business could be adversely affected."

External expectations in relation to performance and reporting across material ESG and sustainability topics, including climate change, environmental performance and modern slavery continue to evolve rapidly. As an ASX-listed company, we currently report against our aspirations, targets and performance across five sustainability pillars: health, safety and security, climate, people, community and environment. Any material incidents or issues that develop within any of these key ESG topics, or a failure to continue to adapt to external expectations in relation to our ESG disclosures, may have a material impact on our access to capital, license to operate, operational or financial performance and our reputation.

Our aspirations, targets and disclosures related to ESG matters, including our decarbonization strategy, expose us to risks, including risks to our reputation, results of operations and financial position.

We have announced a range of ESG goals and targets, and we expect our performance against those targets and the quality of our reporting of our relevant ESG measures to be closely scrutinized by investors, regulators and community and advocacy groups.

In particular, we have stated goals for our carbon emission performance, including continuing to be carbon neutral at the Baúna project (including by the use of offsets) with respect to Scope 1 and 2 emissions. Carbon neutral refers to reducing or avoiding operational Scope 1 and 2 greenhouse gas emissions, acquiring carbon offsets to balance the remaining Scope 1 and Scope 2 emissions, and investing in carbon sequestration initiatives. We also aim to achieve net zero Scope 1 and 2 emissions at the Baúna project by 2035. Net zero refers to reducing Scope 1 and 2 greenhouse gas emissions as far as practical and offsetting the residual greenhouse gas emissions through investment in carbon removal or sequestration initiatives equal or greater to the residual greenhouse gas amount.

We expect that we will need to acquire carbon offset credits in order to meet our stated carbon emissions performance goals. Any changes in regulations on carbon credits, including the potential adoption of the Brazilian Greenhouse Gas Emissions Trading System, may affect if and how we are able to achieve our carbon neutral and net zero goals. See "– Risks relating to our regulatory, tax and legal environment – Our business is subject to extensive laws and regulations that are subject to change in ways that could adversely affect our business and financial position" for more information.

In recent years, there has been rising demand for carbon offset credits in light of a rising number of businesses implementing net zero goals. We cannot guarantee that there will be sufficient carbon offset credits available for purchase when we require them or that offsets we do purchase will successfully achieve the emissions reductions that they represent.

Our ability to implement our climate transition strategy and achieve our targets, including our target of becoming a net-zero for Scope 1 and 2 emissions business by 2035, is subject to risks, including:

- our ability to continue to reduce Scope 1 and Scope 2 emissions in our business;
- the continuing progress of commercially viable technologies to avoid carbon emissions;
- the availability of suppliers that can meet our sustainability and other standards;
- the availability and cost of high-quality, removals-based offsets;
- evolving legislative and regulatory requirements affecting ESG standards, climate goals and obligations, the validity of removal-based offsets and our disclosures;
- evolving standards for tracking and reporting on emissions and emission reductions and removals;
- customers' preferences and use of our products or substitute products;
- the availability of funds to finance initiatives to achieve our targets, including investments in carbon projects; and
- actions taken by our competitors in response to legislation and regulations.

The standards for tracking and reporting on ESG matters continue to evolve. Our selection of disclosure frameworks that seek to align with various voluntary reporting standards may change from time to time and may result in a lack of comparative data from period to period. Disclosure relating to ESG matters is sometimes based on assumptions and calculations that may or may not be representative of actual or forecast risks or events, including any costs associated therewith. Such assumptions and calculations are necessarily uncertain and may be prone to error or subject to misinterpretation given the long timelines involved. Our processes and controls may not always align with evolving voluntary standards for identifying, measuring, and reporting ESG metrics. Our interpretation of reporting standards may differ from those of others, and such standards may change over time, any of which could result in significant revisions to our goals or reported progress in achieving such goals. In addition, regulatory authorities may mandate compliance with certain standards and reporting metrics or require us to audit our ESG data, which may result in increased costs.

Our efforts to achieve ESG aspirations and targets may increase costs or limit or impact our business plans and financial results, potentially resulting in the reduction to the economic end-of-life of certain assets, an impairment of the associated net book value, among other material adverse impacts. Our failure or perceived failure to pursue or fulfill our ESG aspirations and targets or to satisfy applicable reporting standards within the timelines we announce or any perception that we have failed to act responsibly with respect to ESG matters could have a negative impact on investor, community and consumer sentiment towards our business, affect third-party ratings for our approach to ESG matters, increase our cost of capital and expose us to government enforcement actions, private litigation, including class actions and activist campaigns, which may include seeking to pursue binding motions at shareholder meetings, among other materially adverse consequences. See also "– Risks relating to our regulatory, tax and legal environment – Our business subjects us to potential liability from litigation, arbitration and regulatory action."

We rely on a small number of customers for our sales of oil and gas.

We sell all of our oil production from Baúna under a marketing arrangement with SWST, which is a member of the Royal Dutch Shell Plc group. We sell our share of crude oil from Who Dat to BP Products North America Inc., a member of the BP Plc group under a month-to-month evergreen crude oil purchase agreement. We sell our share of natural gas from Who Dat on a six-month seasonal contract basis to BP Energy Company, which is also a member of the BP Plc group, under a gas purchase contract, and we sell our share of natural gas liquids under a life-of-asset sales agreement at prices linked to the Mont Belvieu index as adjusted for the cost of transportation and fractionation to Williams Field Services, a U.S. based natural gas infrastructure provider. If our counterparties or we were to discontinue either of these relationships, any new marketing arrangement we enter may be on less favorable terms and we may incur additional costs to facilitate our marketing and sales. We are also exposed to the risk that SWST, BP Products North America Inc., BP Energy Company or Williams Field Services may fail to settle their payment obligations to us on time. We expect that our contracted receivables under these arrangements will generally constitute substantially all of our trade debtors at any given time. At December 31, 2023, our trade debtors balance was US$40.0 million. If SWST, BP Products North America Inc., BP Energy Company or Williams Field Services fails to meet its obligations to us, it could have a significant adverse effect on our cash flow and liquidity.

An increase in the use of alternative sources of energy could substantially affect the demand for fossil fuels, including the oil and gas that we produce.

The world is experiencing a transformation in the manner in which energy is being produced and consumed. This energy transition involves reducing CO2 emissions, applying new technologies to increase productivity, and increasing the use of alternative sources of energy, such as natural gas, and wind and solar power. Changes to the composition of the global energy matrix and the costs of alternative sources of energy could affect the demand for hydrocarbons and fossil fuels, including the oil and gas that we produce, and could adversely and materially affect us. Additionally, the transition to alternative energy sources may be accelerated by tax advantages and other incentives intended to promote the use of alternative energy, fuel sources or low-carbon technologies. For example, the U.S. Inflation Reduction Act implements various incentives for low carbon activities, including carbon capture and storage and the production of hydrogen and sustainable aviation fuel. These incentives could negatively impact supply and/or demand for our oil and gas products in the future.

We may be adversely and materially affected in the event of a decrease in the demand for oil and natural gas. Additionally, a significant increase in the supply of electricity generated by using alternative fuels could result in a reduction of the price of electricity to end users and adversely affect the demand for oil and natural gas.

We cannot guarantee that future increases in oil and natural gas prices, reductions in the prices of alternative fuels, incentives for the use of alternative energy sources or the generation of electricity from such sources will not have a significant adverse effect on us.

Additionally, the development and implementation of new technologies could result in a significant acceleration in the energy transition. We cannot predict if and when new technologies will become available, the migration flow to these new technologies, as well as their acceptance, and associated costs. The advances in the development of alternative energy sources could significantly reduce the demand for fossil fuels, which means reduced demand for oil and natural gas, which could have a material adverse effect on us.

We could incur substantial costs if we fail to ensure the safety of our employees and contractors.

The nature and complexity of our operations and the environments in which we operate pose risks in relation to the health and safety of the employees and contractors who work in our operations, including risks associated with travel to and from operations. Potential causes of health and safety risks include the failure to control energy or heat during high-risk activities, equipment being operated outside safe operating limits, inadequate and poor implementation of the company management system, poor design and maintenance of physical assets and systems, lack of awareness of major accident prevention processes, insufficient workforce competence, poor practices to identify and escalate risks, failure of third parties to design and implement safe systems, external events such as weather, terrorism and pandemics, and inadequate work planning and resourcing, supervision and contractor management, risk management and controls. If we acquire new operations, these risks may be elevated as we integrate another operator's health and safety practices with our own.

If a safety incident occurs, or we identify an unsafe condition in our operations, we may decide or be required by applicable regulations to shut down the operation until the circumstances have been investigated and remedial action completed.

Any failure to provide safe environments for our workforce, contractors and the public could lead to injury or loss of life, increased operating costs, legal liability, regulatory action, loss of operating licenses, damage to our reputation, negative impacts to staff engagement and poor community and investor sentiment.

Offshore oil operations involve a higher level of operational risk than onshore oil operations and require intensive capital expenditures to access, bring online and repair, which may adversely and materially affect us.

Our oil and gas operations only consist of offshore fields, including deep-water offshore fields. Activities in offshore fields involve greater risks related to mechanical problems, especially when compared to onshore activities, as they require more time and employ more advanced technologies, which results in a higher risk of technological failure and higher costs, increasing the risk of occurrence of accidents involving oil spills, which require the suspension of drilling and production activities.

Offshore operations require intensive capital expenditures to access, bring online and repair, which may increase the financial and operating risks of our standard procedures. These operations are also subject to risks inherent to maritime operations, including maritime disasters and pollution, total loss of vessels, government requirements, inactivity of vessels, defects in equipment, fire, explosions, ship turning, shipwreck, stranding, collision, damage due to adverse weather, risks associated with transshipment and infestations. Due to the limitation and high cost of infrastructure, certain discoveries of offshore reserves may not be economically viable, and if developed, they involve a greater risk of not providing the expected results. Such risks and conditions may materially and adversely affect us.

Our insurance arrangements may be inadequate to cover losses arising from our operations.

We maintain insurance coverage limiting financial loss resulting from certain operating and external hazards. We believe the nature and extent of our insurance cover is reasonable, given the nature of our operations and the availability and cost of insurance, and consistent with industry practice. However, our insurance does not cover all of the risks and potential losses we face, including because insurance is not available for certain risks, we consider the premiums too high relative to the risk or we elect to self-insure by setting aside amounts of cash or liquid securities that we deem sufficient to cover the occurrence of any such risks. We have insurance policies for general liability, physical damage to our oil and gas properties, oil pollution, constructions risk, workers' compensation and employers' liability and other coverage. Additionally we currently carry loss of production insurance, however this insurance is subject to limitations and exclusions, including that it is subject to a 60-day risk retention and does not cover loss of production from named storms, such as hurricanes and cyclones. Loss of production insurance is expensive and may become more expensive in the future. We may discontinue loss of production insurance in the future, particularly if we are able to diversify our base of producing assets.

Our insurance is also subject to deductibles that have to be met prior to recovery and limitations on the insurers' liability with respect to individual claims and the aggregate of our claims. As a result, even if we are insured for an incident, our insurance cover may be insufficient to cover our losses. In addition, insurers may dispute that they are liable or the extent of their liability. The occurrence of a significant event that we are not fully insured against could have a material adverse effect on our financial condition and results of operations. Additionally, insurance policy coverage is conditioned to the payment of the respective premium. If we fail to pay these premiums, we could be placed at risk in the event of an accident since the damages would not be covered by the insurer, which could adversely affect us.

In response to increased premiums or other factors, we may in future change our insurance coverage in ways that increase our exposure to uninsured risks and new risks may emerge for which insurance is not available or too expensive, including climate-related risks. If we make claims under our insurance, our insurers may subsequently increase our premiums or place additional limitations or conditions on our coverage.

We cannot assure that we will be able to maintain our insurance policies in the future at reasonable commercial rates or on acceptable terms with the same insurers or similar insurers, which could increase our costs and, as a result, adversely affect us. We could also be held legally liable to pay damages to third parties as the result of an accident. If any of these factors occur, we could be adversely affected.

The loss of key personnel or a shortage of skilled and semi-skilled labor could adversely affect our business, results of operations and financial position.

We require excellent leaders across our organization who can lead various types of skilled and semi-skilled workers, including employees and contractors, from a range of professions, disciplines, trades and vocations. Our future success is significantly influenced by the expertise and continued service of certain key executive and technical personnel. We cannot assure you that individuals will remain with us for the immediate or foreseeable future. The unexpected loss of the services of one or more of these individuals could have an adverse effect on us and our operations.

The demand for skilled workers in our industry is high, and the supply is limited. In addition, our industry has lost a significant number of experienced professionals over the years due to its cyclical nature, which is attributable, among other reasons, to the volatility in commodity prices.

Constraints on our ability to hire and retain labor with appropriate skills and capabilities could cause a shortage of workers for our company or put increased pressure on wages and costs, which could increase our capital expenditure and operating costs. A considerable period of training and time may be required before new employees and contractors are equipped with the requisite skills to work safely and effectively. We also depend on the ability of our contractors and our joint venture partners to attract and retain suitably skilled and experienced personnel, particularly Altera & Ocyan and LLOG. Our failure, or the failure of our key contractors and joint venture partners, to obtain and retain workers and key personnel could cause a labor capacity shortfall within our business, threaten our ability to deliver on our objectives and have an adverse effect on our business, results of operations and financial position. Similarly, interference with the availability of labor due to industrial action and our inability to secure working visas for overseas labor could also impact negatively on our business performance. Negative perceptions of the oil and gas industry may also affect our ability to recruit.

We rely on IT systems to operate our business, and the failure to protect these systems against cyber security risks, data management risks and other similar incidents could adversely affect our business and disrupt operations.

Our operations rely on a number of IT systems, applications and business processes utilized in the delivery of business functions. Our business depends on computer systems and network infrastructure. In addition, we depend on the integrity of the IT systems of our contractors and joint venture partners, particularly the IT systems used to operate the floating production, storage and offloading facility, *Cidade de Itajaí* and the IT systems used to operate the Who Dat floating production system.

Cyber security risks, including threats to our and our contractors' IT systems from computer viruses, unauthorized access, cyber-attacks and other similar disruptions, have evolved rapidly and can impact all sectors of the economy, including the energy industry. Computers and telecommunication systems are an integral part of our exploration, development and production activities and the activities of our business partners. We use these systems to analyze and store financial and operating data and to communicate within our company and with outside business partners. Technical system flaws, power loss, cyber security risks (including cyber or phishing-attacks), unauthorized access, malicious software, data privacy breaches by employees or others with authorized access, ransomware, and other cyber security issues could compromise our computer and telecommunications systems or those of our business partners and result in disruptions to our critical business processes or the access, fraud and disclosure or loss of our data and commercially sensitive information. In addition, computers control oil and gas production, processing equipment, and distribution systems globally and are necessary to deliver our production to market. A disruption, failure or a cyber-breach of these operating systems, or of the networks and infrastructure on which they rely, could damage critical production, distribution and/or storage assets, delay or prevent delivery to markets, and make it difficult or impossible to accurately account for production and settle transactions. As a result, any such disruption, failure or cyber-breach and any resulting investigation or remediation costs, litigation or regulatory action could lead to reputational damage and have an adverse impact on our results of operations and financial position. In addition, as technologies evolve and cyber security attacks become more sophisticated, we may incur significant costs to upgrade or enhance our security measures to protect against such attacks, and we may face difficulties in fully anticipating or implementing adequate preventive measures or mitigating potential harm.

In addition, we manage personal and sensitive data. There is a risk that poor decisions may be made due to data quality issues or failing to appropriately manage and maintain our data. This includes the capture, processing, distribution, retention and disposal of data. Failure to appropriately manage and maintain our data, including use of data in a manner inconsistent with our obligations and values, or not complying with data management regulatory obligations, may result in a loss of trust, operational disruptions, financial losses or regulatory action.

We may not generate sufficient operating cash flow to make contingent consideration payments we owe to Petrobras.

The agreement under which we acquired Baúna from Petrobras requires us to pay contingent consideration of up to US$285 million plus interest of 2% per annum accruing from January 1, 2019. The amount of this contingent consideration is dependent on future oil prices each calendar year from 2022 to 2026 inclusive, and we are required to begin making payments when the annual average Platts Dated Brent oil prices threshold is above US$50 a barrel. Based on our FY22 internal forecasts, which align with our current internal forecasts, we have assumed that the average Brent crude oil prices from 2022 through 2026 would exceed the US$70 per barrel threshold such that we will have to pay the maximum amount of contingent consideration under this arrangement for each calendar year from 2022 through 2026. This led to us recognizing the present value of the entire contingent consideration arrangement in FY22. To date, we have paid US$170.5 million of this obligation, which includes US$14.5 million of interest. See "Management's discussion and analysis of financial condition and results of operations – Quantitative and qualitative disclosures about market risk – Commodity price risk" for details of the calculation of timing of these payments. Because these payments are tied to oil prices, we will need to generate sufficient cash flow from our Baúna operations to make the required payments. If production is interrupted, or we produce at lower rates than we expect, our operating cash flow may be insufficient to make these payments and we may need to use cash from other sources, including cash flow from other operations or additional borrowings, which may affect our ability to pursue our other objectives, including our growth plans. If we were unable to make a payment of contingent consideration to Petrobras, we would be in breach of contract and subject to the risk of Petrobras bringing a claim for specific performance under the Brazilian Civil Code against us, which could materially impact our financial position and ability to operate our business.

Any outbreak of a contagious disease may adversely affect our business, financial condition and results of operations.

Any outbreak of a contagious disease may adversely affect our business, financial condition and results of our operations. For example, our business and operations were adversely affected by the COVID-19 pandemic and the associated reduction in demand for oil and gas, which resulted in a major downturn in commodity prices during 2020. COVID-19 and the related actions taken by governments and businesses to manage the pandemic, including voluntary and mandatory quarantines and restrictions on movement and travel, resulted in a significant and swift reduction in global economic activity. As a result of COVID-19, our operations, and those of both our local and global business partners, service companies and suppliers, experienced adverse effects, including, disruptions, delays or temporary suspensions of operations and supply chains, temporary inaccessibility or closures of facilities, and workforce impacts from illness, lack of availability (arising from domestic and/or international travel restrictions), school closures and other community response measures.

Any resurgence or outbreak of a contagious disease and resulting actions by governments and businesses to manage the spread of any disease could result in a recurrence of similar adverse conditions that characterized the COVID-19 pandemic, which may adversely affect our business, financial condition and result of operations.

Risks relating to our financial arrangements

We have debt, and may incur more debt in the future, which may adversely affect our business, financial condition and ability to pursue our growth objectives, and may impact our ability to repay our obligations, including under the Notes.

As of December 31, 2023, we had a total principal amount of US$274.1 million of debt outstanding and US$66.0 million of unavailable and unused commitments available under our RBL facility. Debt outstanding under the RBL facility will be effectively senior in right of payment to the Notes to the extent of the value of the Collateral securing the RBL facility. We expect to incur additional debt through the issuance of the Notes, although we intend to use a portion of the proceeds of this issuance to repay the RBL facility, which will then be available to be redrawn. As of December 31, 2023 on an as adjusted basis after giving effect to (i) the offering of Notes contemplated hereby, (ii) the repayment of our prior reserve-based, non-recourse, syndicated loan facility (which was repaid and canceled after December 31, 2023) and (iii) the repayment of the outstanding amount of the RBL facility as described under "Use of proceeds", the Notes will constitute our only substantial financial indebtedness. Subject to customary conditions to draw, US$246.0 million would be available immediately to be redrawn under the RBL facility, which indebtedness would be first-priority secured indebtedness and therefore effectively senior to the Notes. We expect that when our interest in the Who Dat assets is added to the borrowing base, the full US$340.0 million committed under the RBL facility will become available, subject to customary conditions to draw. Under our existing debt instruments, including the indenture governing the Notes, we will be able to incur substantial additional indebtedness. Our debt level may increase significantly in the future, particularly if we incur additional debt to fund acquisitions.

Our debt levels may affect our business in the future, including by requiring us to devote a significant proportion of our cash flow from operations to servicing interest payments on our debt, reducing the cash available for other purposes, including working capital and capital expenditure to sustain our operations and invest in growth projects. High debt levels increase our vulnerability to adverse economic conditions, including a sustained downturn in oil and gas prices or significant cost increases. In these conditions, we may find it difficult to satisfy our obligations under our debt instruments, including the Notes, and we may be unable to refinance maturing debt. Our debt level may impair our ability to pursue opportunities to grow our business, including by limiting our ability to obtain additional financing. See also "– The covenants in our debt facilities, including the Notes, may limit our ability to finance our operations and pursue our growth plans."

If we are unable to raise funds on favorable terms, including in order to fund our growth projects and any future acquisitions and refinance our existing debt, our business could be adversely affected.

We rely on access to debt and equity financing to conduct our business, in particular, to fund our growth projects and any future acquisitions we may undertake, as well as to refinance our existing debt ahead of its maturity. There is a risk that we may not be able to access equity or debt capital markets to support our business objectives, or successfully refinance our current debt facilities on commercially favorable terms, or at all.

Our ability to secure financing (or financing on acceptable terms) may be adversely affected by volatility in the financial markets, a financial crisis, destabilizing events and disruption to the geopolitical environment and our industry or economic sector, or by a downgrade in our credit ratings. For example, in recent years, debt capital markets have been affected by volatility related to uncertainty about the impact of the COVID-19 pandemic and subsequently by sharp increases in interest rates as central banks sought to counter high inflation. In addition, over the past few years, certain financial institutions, institutional investors and other sources of capital have begun to limit or exit their investment in oil and gas activities citing concerns about climate change and ESG, which could make it more difficult and expensive to finance our business. For these or other reasons, financing may be unavailable to us or our cost of financing may be significantly increased. Such inability to obtain, or an increase in the costs of, financing could materially and adversely affect our business, results of operations and financial position. See "Management's discussion and analysis of financial condition and results of operation – Quantitative and qualitative disclosure around market risk – Interest rate risk" and "– Risks relating to the Notes and Security – Our variable rate indebtedness subjects us to interest rate risk, which could cause our debt service obligations to increase significantly."

We seek to maintain sufficient liquid assets and available committed credit facilities to meet short-term and medium-term liquidity requirements. As of December 31, 2023, we had total available liquidity of US$170.4 million, all of which was cash and cash equivalents and outstanding borrowings of US$274.1 million, all of which was first-lien senior secured debt. As of December 31, 2023, we also had US$66.0 million undrawn under our RBL facility, all of which was committed but unavailable due to the borrowing base limit under our RBL facility, pending the addition of our interest in the Who Dat assets to the RBL facility borrowing base assets. See "Management's discussion and analysis of financial condition and results of operations – Liquidity and capital resources – Financing arrangements." If we fail to manage our liquidity position properly in the future, or if markets are not available to us at the time that we require any financing, there is a risk that our business and financial flexibility may be adversely affected.

We are exposed to foreign currency risk and foreign exchange regulations.

Our foreign exchange risk exposures primarily relate to our corporate overheads and business development expenditures, which are incurred in Australian dollars, and some of our operating and capital expenditures related to our Baúna production assets and the payment of Brazilian taxes, which are incurred in Brazilian real.

We generally do not hedge these exposures, but manage them from a liquidity perspective by forecasting our cash flows and ensuring that we hold sufficient Brazilian real and Australian dollar cash balances. However, these balances do not usually exceed the foreign currency amounts we estimate that we will need over the next three months.

Foreign exchange and foreign credit transactions in Brazil are subject to Central Bank regulations and specific legislation. Foreign credit transactions above certain thresholds are subject to reporting to the Central Bank. Exceptional and emergency cases related to a serious imbalance or an anticipated serious imbalance of Brazil's balance of payments may impose temporary restrictions on remittances of foreign capital abroad. Such restrictions may adversely affect the Bank's business, operations, or prospects and its ability to make foreign currency payments on its obligations outside Brazil.

We can give no assurances that we will successfully manage our exposure to exchange rate fluctuations and that exchange rate fluctuations or Brazilian foreign exchange regulations will not have a material adverse effect on our future financial position and performance.

The covenants in our debt facilities, including the Notes, may limit our ability to finance our operations and pursue our growth plans.

The indenture will restrict and the RBL facility restricts, among other things, our ability to:

- incur additional debt and issue guarantees and preferred stock;
- make certain payments, including dividends and other distributions, with respect to outstanding share capital;
- repay or redeem subordinated debt or share capital;
- create or incur certain liens;
- impose restrictions on the ability of our subsidiaries to pay dividends or make other payments to the Company and other subsidiaries;
- in the case of the RBL facility, make certain modifications to or terminations of our contractual arrangements, and exercise certain rights on operating or similar committees, with respect to our borrowing base assets;
- operate certain bank accounts relating to our borrowing base assets;

- make certain investments (including acquisitions and joint ventures) or loans and provide certain guarantees of performance obligations;
- sell, lease or transfer certain assets, including shares of any of our restricted subsidiaries;
- guarantee certain types of our other indebtedness without also guaranteeing the Notes;
- expand into unrelated businesses;
- merge or consolidate with other entities; and
- enter into certain transactions with affiliates

All these limitations are subject to significant exceptions and qualifications. See "Description of the Notes – Certain Covenants." Our compliance with these covenants could reduce our flexibility in conducting our operations, particularly by among other things:

- limiting our ability to react to changes in market conditions, whether by increasing our vulnerability in relation to unfavorable economic conditions or by preventing us from profiting from an improvement in those conditions;
- affecting our ability to pursue business opportunities and activities that may be in our interest;
- limiting our ability to obtain certain additional financing in order to meet our working capital requirements, make investments or acquisitions and carry out refinancings; and
- requiring us to dedicate a significant portion of our cash flows to payment of the sums due for such loans, thus reducing our ability to utilize our cash flows for other purposes.

In addition, we are subject to affirmative and financial covenants contained in the RBL facility, including the requirement to maintain a specified ratio of net debt to EBITDAX, as defined in the RBL facility and, with respect to the Borrowing Base Obligors, a minimum liquidity ratio, minimum cash balance and minimum debt service coverage ratio. See "Description of other financing arrangements." Our ability to meet financial ratios and other tests can be affected by events beyond our control, and we cannot assure you that we will meet them. A breach of any of those covenants, ratios, tests or restrictions could result in an event of default under the RBL facility or the indenture. If an event of default occurs under the RBL facility, subject to applicable cure periods and other limitations on acceleration or enforcement, the relevant creditors could cancel the availability of the facilities and elect to declare all amounts outstanding, together with accrued interest, immediately due and payable. The RBL facility would also limit or prohibit us from withdrawing funds from bank accounts that consist of amounts that we have received in connection with certain assets or any disposal of such assets or of any subsidiary that holds, whether directly or indirectly, any such asset. In addition, any default under the RBL facility could lead to an event of default and acceleration under other debt instruments that contain cross-default or cross-acceleration provisions, including the indenture. If our creditors, including the creditors under the RBL facility accelerate the payment of those amounts, we cannot assure you that our cash flow or our assets and the assets of our subsidiaries would be sufficient to repay in full such amounts, to satisfy all other liabilities of our subsidiaries which may be due and payable and to repay amounts outstanding under the Notes. If we are unable to repay the amounts due and payable under the RBL facility, our creditors thereunder could proceed against the Collateral that secures such debt. Accordingly, we could be forced into bankruptcy or liquidation, and the Company and Guarantors may not be able to fulfill their respective obligations under the Notes and the Guarantees.

Risks relating to our regulatory, tax and legal environment

Our business is subject to extensive laws and regulations that are subject to change in ways that could adversely affect our business and financial position.

Our business is subject to numerous laws and regulations in each of the jurisdictions in which we operate.

These relate to the exploration, appraisal, development, production, marketing, pricing, processing, refining, transportation and storage of our products, as well as the royalties, taxes and other imposts we must pay to applicable government authorities and landowners in connection with our activities. They also regulate how we conduct our business and operations, including our capacity to move capital between jurisdictions. A change in government and/or the laws, which apply to our business or the way in which we are regulated, could have a material adverse effect on our business, results of operations and financial position. For example, a change in taxation laws, environmental laws, health and safety laws, competition laws or the application of other existing laws or new laws, including any laws relating to climate change and/or greenhouse gas emissions, could also have a material effect on us. In addition, non-compliance with such laws and regulations, including non-compliance with our fundamental duties under laws and regulations applicable to corporations, labor, and competition and consumer legislation, could have an adverse effect on us and result in the assessment of administrative, civil or criminal penalties, issuance of remedial obligations and imposition of injunctions limiting or prohibiting certain of our operations. It is not uncommon for the governments of jurisdictions in which we operate to review the markets, laws, and regulations that impact our business from time to time, and this can lead to changes in the regulatory environment in which our joint venture partners or we operate.

In particular, the economic viability of our operations depends on the fiscal and regulatory regimes applicable to oil and gas operations in Brazil and the United States. See "Regulatory overview" for a summary of the principal features of these regimes that affect our business. Changes to these fiscal or regulatory regimes could increase our costs, require us to expend capital to keep our operations in compliance, increase our existing liabilities or create new liabilities, increase our royalty or tax obligations, any of which may have a material adverse effect on the profitability and viability of the affected operations.

We depend on exploration and production licenses that are conditional and may be subject to modification or withdrawal, and we may be unable to timely obtain, maintain or renew such licenses.

Our exploration for resources and our production of reserves depends on us being granted and maintaining appropriate licenses, permits, regulatory consents and authorizations. The process of obtaining licenses is long and intensive and often requires us to submit detailed plans that comply with regulatory requirements, prepare a large volume of supporting information and give a range of undertakings to regulators, including financial security. We may not be successful in obtaining, maintaining or renewing the licenses we need to pursue our business plans, including obtaining these in a timely manner, the granting of which may be subject to considerable discretion on the part of regulators and governments.

Once granted, licenses are usually subject to a range of conditions regarding the way we conduct our operations, including that we comply with applicable law. Exploration and development licenses often require us to spend minimum amounts of capital on our activities and reach milestones by certain dates, failing which our licenses may be canceled. Licenses may be subject to subsequent government action such as alteration, imposition of additional conditions or withdrawal, either pursuant to statutory discretions or otherwise. Such additional requirements may render a project economically unfeasible. Regulatory authorities may conduct announced and unannounced inspections of our operations. If we were to be found in noncompliance with one or more conditions of our licenses, we may be required to temporarily suspend our operations in part or in full, lose our licenses or be subject to civil, criminal or administrative liability, which could have a material impact on our operations and financial position.

Under Brazilian law, oil and gas activities are controlled and regulated by the Brazilian federal government, which grants, by means of a concession contract, a production sharing contract or a transfer of rights contract, the right to oil and gas exploration, development and production. All of our existing exploration and production rights are currently governed by concession contracts, which have been entered into with the ANP, whether directly (which is the case for the Neon, Goiá and Clorita fields) or through an assignment procedure with the ANP (which is the case for the Baúna field).

Under the terms of the Petroleum Law and concession contracts, these contracts may be subject to early termination in certain events, such as (i) failure to comply with the obligations established in the concession contracts, including, without limitation, failure to complete the minimum exploratory program, failure to timely submit the development plan to the ANP or failure to obtain ANP approval to the development plan; or (ii) bankruptcy of the party to the concession contract, in case if such party is unable to present a recovery plan duly approved that demonstrates to ANP the financial capacity to fulfill the contractual and regulatory obligations. In the case of early termination of the concession agreements, the conceded assets must be returned to the Brazilian federal government, and if the concessionaire has given cause to the early termination event, the concessionaire is not entitled to compensation, and may be subject to penalties.

The Brazilian federal government may also decide to unilaterally terminate the concession contracts or recover conceded assets by means of expropriation due to public interest, in which case the concessionaire is entitled to receive an indemnification. While there are no known instances of expropriation due to public interest in the past, if this were to occur, indemnity payments may not be sufficient to offset the investment we made.

The early termination of concession contracts will not release us from liability for losses and damages caused to third parties in connection with the concession granted, subject to the applicable statutory limitations and delay periods. Further, the early termination of concession contracts will not release us from obligations owed to our creditors.

In the event that a concession contract is terminated due to non-compliance with legal, regulatory or contractual provisions, any indemnity to be paid by the Brazilian federal government may be significantly reduced by the imposition of fines or other penalties.

In addition, in the case of early termination of present or future concession contracts, it is not possible to ensure that the amount of any indemnity will be sufficient to offset the investment made, the implied rate of return or the loss of future profit on assets not yet fully amortized. Concession contracts under which we are authorized to explore and produce oil and natural gas are subject to set expiration dates. Although we may want to extend concessions with the ANP beyond their original expiration dates, there is no assurance that the ANP would agree to such extension or, if ANP does so agree, that it would agree on terms that are acceptable to us, which may have a material adverse effect on our business, financial condition or results of operations. If the concession contracts are terminated, any assets, real property, equipment or facilities within the concession areas required for production or considered of public interest may revert to the ANP, without any additional compensation to us.

Several of our leases in the US Gulf of Mexico are subject to expiration within 2024 and 2025 unless drilling operations or production in paying quantities commences. In January 2024, LLOG has applied for unitization of leases in the Who Dat East field. The application is currently subject to regulatory review by the Bureau of Safety and Environmental Enforcement ("BSEE"). If successful, these leases or parts thereof would be combined with respective other existing leases that our joint venture holds by production and operated as a single unit with production or operations from one tract in the unit being treated as production or operations from every tract included in the unit. If one or more of our applications for unitization are not granted, we may be required to suspend our operations on the respective lease in part or in full or lose our licenses, which could have a material impact on our operations and financial position. See also "Business – Our concession agreements and leases."

We can give no assurances that the licenses, permits, regulatory consents and authorizations will be renewed or granted or as to the terms of such renewals or grants. Moreover, if we do not meet our work and/or expenditure obligations under permits and licenses, this may lead to diminution of our interest in, or the loss of, such permits and licenses.

The costs of complying with environmental laws may increase, and we may incur substantial liabilities if an environmental incident occurs.

A range of environmental risks exist within oil and gas exploration, development and production activities. We operate in a number of highly environmentally sensitive areas. Environmental incidents and real or perceived threats to the environment or the amenity of communities could result in a loss of our social license to operate leading to delays, disruption to or the shutdown of current exploration and/or future production activities.

Our activities may result in environmental impacts, which may, in turn, give rise to substantial costs for environmental rehabilitation, damage control and losses. For example, we have been subject to fines by ANP in connection with the occurrence of oil sheen exceeding authorized levels at our operations in the Santos Basin from time to time. If we fail to manage our operational hazards and comply with environmental and safety requirements, such failure could lead to regulatory or environmental action, legal liability, material cost and reputational damage. Oil spills and leaks in the ocean can be particularly costly to remediate because of the propensity for damage to occur over a wide area and the environmental sensitivity of marine and coastal environments. Liability could be imposed on us without regard to our fault in the matter. For example, in the context of damages caused by oil spills and leaks both Brazilian and US rules provide for joint, several and strict civil liability under environmental laws.

With increasing government and public sensitivity to climate change and environmental sustainability, environmental regulation is becoming more stringent. We could be subject to increasing environmental responsibility and liability, including laws and regulations dealing with greenhouse gases and other air emissions, water, noise, losses of hydrocarbon and other discharges of materials into the environment, fauna and flora protection, the reclamation and restoration of our properties, and rehabilitation of the environment, hydraulic stimulation, the storage, treatment and disposal of wastes and the effects of our business on the marine environment. When we operate in new jurisdictions, we become subject to new regulations that may be more stringent or differ from those with which we have experience. Failure to manage these risks effectively could lead to concerns over the sustainability of our business.

Sanctions for non-compliance with these laws and regulations may include administrative, civil and criminal penalties, civil liability, revocation of licenses, permits, regulatory consents and authorizations, reputational issues, increased authorization conditions and corrective action orders. These laws sometimes apply retroactively. In addition, a party can be liable for environmental damage without regard to that party's negligence or fault.

Increased costs associated with regulatory compliance and/or with litigation could have a material and adverse effect on our earnings and cash flows. Increased environmental activism, including in the form of activist shareholder campaigns, also presents potential increased costs and reputational risks, including time spent by management with respect to managing and responding to governments, regulators, investors and activists.

Additional drilling laws, regulations, executive orders and other regulatory initiatives that restrict, delay or prohibit oil and natural gas exploration, development and production activities or access to locations where such activities may occur could have a material adverse effect on our business, financial condition or results of operations.

Our operations may become subject to additional drilling laws, regulations, executive orders or other regulatory initiatives limiting oil and natural gas exploration, development or production. For example, the US administration has recently taken a number of actions that may result in stricter environmental, health and safety standards applicable to our operations in the US Gulf of Mexico.

In January 2021, President Biden issued an executive order suspending new leasing activities for oil and natural gas exploration and production on federal lands and offshore waters pending review and reconsideration of federal oil and natural gas permitting and leasing practices. After a group of states challenged the executive order, a federal judge required the U.S. Department of Interior (the "DOI") to stop the leasing pause. These lease sales are conducted pursuant to five-year leasing programs under the Outer Continental Shelf Lands Act. In September 2023, consistent with the requirements of the U.S. Inflation Reduction Act (the "IRA") concerning offshore conventional and renewable energy leasing, the DOI announced its proposed 2024-2029 National Outer Continental Shelf Oil and Gas Leasing Program (an "OCS Program"). The proposed OCS Program includes a maximum of three potential oil and natural gas lease sales in the Gulf of Mexico scheduled in 2025, 2027 and 2029. This is the fewest number of lease sales in the program's history and the minimum amount needed to continue expanding an offshore wind program under the IRA, which does not allow offshore wind leases unless enough oil and gas leases are offered the year before. Moreover, it is likely that the new five-year leasing program will be subject to heightened environmental review. It is also possible that the program could be delayed by opposing lawsuits that were filed on February 12, 2024 by the American Petroleum Institute and by Earthjustice representing multiple environmental groups both of which are challenging the Bureau of Ocean Energy Management's ("BOEM's") actions. Future actions taken by the Biden Administration to limit the availability of new oil and gas leases on the Outer Continental Shelf ("OCS") would adversely impact the offshore oil and gas industry and impact demand for our products.

In addition, over the past decade, BSEE and BOEM have imposed new and more stringent permitting procedures and regulatory safety and performance requirements for new wells to be drilled in United States federal waters. For example, in August 2023, BSEE published a final rule, effective October 23, 2023, to clarify and modify certain blowout preventer system requirements. The rule requires, among other things, that the blowout preventer system is able to close and seal the wellbore at all times to the well's maximum kick tolerance design limits and includes more stringent requirements for failure reporting.

Compliance with any added or more stringent regulatory requirements in the United States or Brazil or enforcement initiatives and existing environmental and spill regulations, together with uncertainties or inconsistencies in decisions and rulings by governmental agencies and delays in the processing and approval of drilling permits and exploration, development, oil spill response and decommissioning plans could result in difficult and more costly actions and adversely affect or delay new drilling and ongoing development efforts.

These regulatory actions, or any new laws, executive orders, regulations or other legal or enforcement initiatives, that impose increased costs or more stringent operational standards could delay or disrupt our operations, result in increased supplemental bonding and associated costs, and limit activities in certain areas, or cause us to incur penalties, fines, or shut-in production at one or more of our facilities or result in suspension or cancellation of leases. Also, if material spill incidents were to occur in the future, the United States, Brazil or other countries where such an event may occur could elect to issue directives to temporarily cease drilling activities and, in any event, may from time to time issue further safety and environmental laws and regulations regarding offshore oil and natural gas exploration and development, any of which could have a material adverse effect on our business. We cannot predict with any certainty the full impact of any new laws or regulations on our drilling and production operations or on the cost or availability of insurance to cover some or all of the risks associated with such operations. See "– Risks relating to our industry and operations – Our insurance arrangements may be inadequate to cover losses arising from our operations."

We are exposed to political risk in Brazil and the United States.

Our interests in Brazil and the United States are subject to political, economic, social and other uncertainties, including the risk of expropriation, nationalization, renegotiation or termination of existing contracts, licenses and permits or other agreements, changes in laws or taxation policies, currency exchange restrictions and changing political conditions, insurrection, acts of terrorism, civil rebellion, border and territorial disputes and war. Both Brazil and the United States have been subject to political instability, including violent protests against election results, and the immediate past president of each country is currently awaiting trial on criminal charges relating to their conduct in office.

Political instability could result in more volatile or extreme policy-making, undermine confidence in government processes and the rule of law or result in civil unrest. A more volatile political environment may increase the risk of governments taking actions that adversely affect our business, such as expropriation or nationalization, without appropriate processes or compensation. Political instability could undermine investor confidence in the affected jurisdiction, resulting in a redirection of capital, reducing the value of our assets and making it more difficult for us to refinance our debt or obtain new finance.

The effects of these factors are difficult to predict and any combination the above may have a material adverse effect on the operation or development of our business and/or the ownership or control of our assets.

The Brazilian government exercises significant influence over the Brazilian economy. This influence, as well as Brazilian political and economic conditions, may materially and adversely affect us.

The Brazilian government has frequently intervened in the Brazilian economy and has occasionally made significant changes in policy and regulations, influencing the Brazilian economy. The Brazilian government's actions to control inflation and the implementation of policies and regulations have often involved, among other measures, interventions in interest rates and in the foreign exchange market, changes in tax policies, price controls, capital controls and limits on imports. We cannot control or predict which measures or policies will be adopted by the Brazilian government in the future. We may be materially and adversely affected by changes in policies or regulations involving or affecting factors, including:

- oil and gas prices in Brazil and abroad;
- interest rates;
- foreign exchange controls and restrictions on remittances abroad;
- exchange rate fluctuations;
- changes in labor and regulatory rules;
- tax policies and changes in tax laws;
- import and export controls;
- increased unemployment;
- economic, social and political instability; and
- other political, diplomatic, social, environmental, climate and economic developments in or affecting Brazil.

We are subject to, and may become liable for any violations of anti-corruption, anti-bribery, anti-money laundering, sanctions and similar laws.

We are subject to anti-corruption, anti-bribery and anti-money laundering, sanctions and similar laws and regulations in the jurisdictions in which we operate and the jurisdictions whose laws govern our financial arrangements. These laws include the U.S. Foreign Corrupt Practices Act, the Brazilian Clean Companies Act (Law No. 12,846/2013), the Australian Autonomous Sanctions Act 2011 (Cth), the Anti-Money Laundering and Counter-Terrorism Financing Act 2006 (Cth), the Charter of United Nations Act 1945 (Cth) and the Australia Criminal Code Act 1995 (Cth) and generally prohibit companies, their agents, their contractors and company employees from engaging in bribery or other prohibited payments to government officials, directly or indirectly, for the purpose of obtaining or retaining business, implement restrictions on certain business relationships and require companies to maintain accurate books and records and internal controls. In the future, we may face, directly or indirectly, corrupt demands by officials, tribal or insurgent organizations or private entities. Thus, we face the risk of unauthorized payments or offers of payment by one of our employees, joint venture partners, consultants or third-party agents, given these parties may not always be subject to our control.

We deal with a broad range of counterparties on a regular basis through our business relationships and contracts. Given the nature of our operations and activities, we are, in particular, exposed to the risk of violations of anti-corruption and anti-bribery laws in connection with our operational, marketing, trading and procurement activities in Brazil. Brazil was ranked 104th out of 180 countries and territories in Transparency International's 2023 Corruption Perception Index, which lists countries according to their perceived levels of corruption, as determined by expert assessments and opinion surveys. Numerous members of the Brazilian government and of the legislative branch, as well as senior officers of large state-owned and private companies have been convicted of political corruption due to officials accepting bribes by means of kickbacks on contracts granted by the government to several infrastructure, oil and gas, and construction companies, among others.

A company may be found liable for violations by not only its employees but also by its contractors and third-party agents. Our internal procedures and policies may not always be effective in ensuring that our employees, contractors, third-party agents or we will comply strictly with all such applicable laws. If we become subject to an enforcement action or we are found to be in violation of such laws, this may have a material adverse effect on our reputation and may possibly result in significant penalties or sanctions and may have a material adverse effect on our business, financial condition or results of operations.

Laws regulating greenhouse gas emissions could adversely affect the cost, manner and feasibility of doing business and demand for the oil and gas that we produce.

Our operations and properties generate greenhouse gas emissions and hydrocarbons, which contribute to climate change. A number of governments and governmental bodies, including those in Australia, Brazil and the United States have introduced laws and regulations to reduce greenhouse gas emissions, and they may expand these laws and regulations in the future. These laws have increased and may continue to increase our operating and compliance costs. There remains significant uncertainty regarding the future of climate change regulation and the effect it may have on our business, although the social and governmental focus on climate change is likely to result in further regulation of industries and companies that generate greenhouse gas emissions.

In addition, there have been a number of legislative and regulatory initiatives proposed in recent years in an attempt to control or limit the effects of climate change, including greenhouse gas emissions, and to respond to commitments under international agreements, such as the 2016 Paris Agreement on climate change. See "– Our business is subject to extensive laws and regulations that are subject to change in ways that could adversely affect our business and financial position."

Future legislation or regulation mandating reductions in greenhouse gas emissions could have far-reaching and significant impacts on our operations and on the energy industry. We anticipate that our activities will be subject to increasing regulation and costs associated with climate change and the management of greenhouse gas emissions, including through the increased risk of investigations and litigation pursuant to any related legislation or regulation. Such regulations could result in increased costs to operate our facilities or additional operating restrictions on our business, capital expenditures to install new emission controls at our facilities, and costs to administer and manage any potential greenhouse gas emissions or carbon-trading or tax programs, which may rely on our ability to obtain sufficient carbon offset credits at a commercially reasonable price.

These potential further regulations and initiatives could also restrict or impose additional cost on fossil fuel use and promote energy efficiency and lower emission energy sources. This may reduce demand for our products and could reduce the prices that we receive, thereby reducing our revenues and adversely impacting our earnings, reserves and resources. Effective stakeholder opposition, non-governmental activism and interest groups lobbying for increased climate change regulation also have the potential to delay project schedules and the production of oil, gas or both, and may also increase the costs of project execution.

Our provisions for future removal and environmental restoration costs may underestimate our future costs, which could result in impairment charges or higher costs than we anticipate.

Our oil and gas operations are subject to laws and regulations that require us to close and restore our wells, pipelines, facilities and other assets after they cease to produce or are no longer economically viable. At that point, we will incur substantial costs for, among other things, removing facilities and decommissioning wells and restoring the affected areas. We recognize accounting provisions reflecting our best estimate of the present value of the future expenditure required to settle the restoration obligation at the reporting date, based on current legal requirements or observed industry analogues. We update our restoration provisions regularly, and adjustments in our estimates are reflected in the present value of the restoration provision at the reporting date, with a corresponding change in the cost of the associated asset.

As discussed in more detail under "Management's discussion and analysis of financial condition and results of operations – Critical accounting policies – Provision for restoration" and Note 16 to our TY23 audited financial statements, we record accounting provisions for the estimated present value of our future closure and restoration obligations based on our best estimates of the timing and amount of the expenditures. However, these estimates are subject to significant uncertainties and may change over time due to various factors, such as changes in laws and regulations, environmental conditions, operating plans, asset performance, inflation, discount rates, and technological developments. For example, because we own assets in the US Gulf of Mexico, platforms, facilities and equipment are subject to damage or destruction as a result of hurricanes and other adverse weather conditions. The estimated costs to plug and abandon a well or dismantle a platform can change dramatically if the host platform from which the work was anticipated to be performed is damaged or toppled rather than structurally intact. Also, a sustained lower commodity price environment may cause our joint venture partners to be unable to pay their share of costs, which may require us to pay our proportionate share of the defaulting party's share of costs.

As a result, our actual closure and restoration costs and liabilities may differ materially from our accounting provisions, and we may incur additional charges or adjustments to our financial statements in the future. Any such charges or adjustments could have a material adverse effect on our financial condition and results of operations.

In September 2023, we provided a surety bond in the amount of US$98.2 million (as of December 31, 2023) to ANP in connection with existing decommissioning obligations relating to the Baúna field in Brazil. This surety bond replaced and topped up a company guarantee we provided previously. As of the date of this offering memorandum, we continue to await regulatory approval from ANP. In connection with the acquisition of our US Gulf of Mexico assets, we acceded into several decommissioning security agreements with the BOEM and expect to make financial contributions under these agreements from 2030 onwards.

The surety bond was provided in connection with the obligation set forth in ANP Resolution No. 854/2021, which regulates the procedures for provision of financial guarantees and terms to secure the financial resources for the decommissioning of production facilities in oil and natural gas fields, based on the adoption of progressive contributions. In addition, such resolution establishes the guarantees accepted by the ANP, namely letters of credit, corporate collaterals, provisioning funds, oil and natural gas pledge, performance bonds or the execution of extrajudicially enforceable instruments. In order to be approved by ANP, the guarantees submitted must follow the requirements provided under ANP Resolution No. 854/21. ANP may order the replacement of the adopted guarantee at any time, including whenever a technical study shows that the provided guarantee is insufficient or inadequate. If we fail provide the guarantee for the decommissioning in assignment proceedings pending with the ANP, the assignment will not be completed, as the guarantee is a requirement set forth in ANP Resolution No. 854/21. If we fail to renew the decommissioning guarantees, the guarantee originally provided may be foreclosed by ANP, pursuant to ANP Resolution No. 854/21, and we may be subject to the penalties set forth in Law No. 9,847/1999 for non-compliance with requirements set forth in applicable law and in ANP Resolutions. For further information, please see "Regulatory overview – Decommissioning" and "Regulatory overview – Regulatory overview – Brazil – Decommissioning."

In the United States, the BOEM currently requires all lessees of an OCS oil and natural gas lease to post base bonds ranging from US$50,000 to US$3.0 million in addition to supplemental financial assurance determined based on the lessee's ability to carry out present and future financial obligations. In June 2023, the BOEM proposed a new rule that updated the criteria for determining whether oil and natural gas lessees may be required to provide supplemental financial assurance to ensure compliance with the Outer Continental Shelf Lands Act. A final rule was published on April 15, 2024 and we are considering its impact on our operations. If our joint venture becomes subject to significantly higher bonding obligations, we may be required to pay additional costs and experience an adverse impact on our financial position. Moreover, the implementation of the new rule could result in sureties seeking additional collateral to support existing or future bonds, such as cash or letters of credit, and we cannot provide assurance that our joint venture will be able to satisfy collateral demands for such bonds to comply with supplemental bonding requirements of BOEM. If we are required to provide collateral in the form of cash or letters of credit, our liquidity position could be negatively impacted, and we may be required to seek alternative financing. These and other changes to BOEM bonding and financial assurance requirements could result in increased costs on our operations, reduced cash flows if unable to comply and consequently have a material adverse effect on our business and results of operations.

Our business exposes us to potential tax liabilities that could have an adverse impact on our results of operations.

In addition to the standard level of income tax imposed on all industries, as a company in the petroleum and gas industry, we are required to pay additional taxes in the form of government royalties on petroleum production, direct and indirect taxes and other imposts in the jurisdictions in which we operate. See "Business – Brazil – Producing asset – Báuna – Licensing and royalties" and "Business – US Gulf of Mexico – Producing asset – Who Dat – Licensing and royalties" for more detail on the tax and royalty regimes to which our operations are subject. Our after-tax profitability could be affected by numerous factors, including the availability of tax credits, exemptions, refunds (including refunds of value added taxes) and other benefits to reduce our tax liabilities, changes in the relative amount of our earnings subject to tax in the various jurisdictions in which we operate or have subsidiaries, the potential expansion of our business into or otherwise becoming subject to tax in additional jurisdictions, changes to our existing business structure and operations, the extent of our intercompany transactions and the extent to which taxing authorities in the relevant jurisdictions respect those intercompany transactions.

From time to time, federal and state level legislation in the United States has been proposed that would, if enacted into law, make significant changes to tax laws, including to certain key U.S. federal and state income tax provisions currently available to oil and natural gas exploration and development companies. Such proposed legislative changes have included, (i) the elimination of the percentage depletion allowance for oil and natural gas properties, (ii) the elimination of current deductions for intangible drilling and development costs, (iii) an extension of the amortization period for certain geological and geophysical expenditures, (iv) the elimination of certain other tax deductions and relief previously available to oil and natural gas companies and (v) an increase in the U.S. federal income tax rate applicable to corporations (such as us). U.S. states in which we operate or own assets may also impose new or increased taxes or fees on oil and natural gas extraction. It is unclear whether these or similar changes will be enacted and, if enacted, how soon any such changes could take effect. Future tax legislative or regulatory changes in the United States, Brazil or in any other jurisdictions in which we operate now or in the future could also adversely impact our after-tax profitability.

Additionally, these tax regimes can be subject to differing interpretations and tax rules in any jurisdiction are subject to legislative change and changes in administrative and regulatory interpretation. Our interpretation of applicable tax law may not coincide with that of the relevant tax authorities. As a result, transactions may be challenged by tax authorities and any of our profits from activities in those jurisdictions in which we operate may be subject to additional tax or additional unexpected transactional taxes (e.g., stamp duty, VAT or capital gains tax), which, in each case, could result in significant legal proceedings and additional taxes, penalties and interest, any of which could have a material adverse effect on our business, prospects, financial condition and results of operations. In addition, taxing authorities could review and question our tax returns leading to additional taxes and penalties, which could be material. Currently, there are also different bills under discussion in the Brazilian Congress that seek to implement tax reforms, including proposals to modify the taxation applicable to legal entities. See "– There are several tax reforms under consideration in Brazil, which may adversely impact our tax obligations."

We seek to maintain a constructive and transparent relationship with taxation revenue authorities in each jurisdiction in which we operate. From time to time, we may disagree with taxation authorities on the interpretation of taxation laws. Where such differences meet the necessary criteria, they will be reflected in our financial statements accordingly. Our financial position and results of operations may be negatively impacted should a relevant authority disagree with a tax position we have adopted and we are ultimately unsuccessful in maintaining that position through various avenues of appeal (including a court appeal).

There are several tax reforms under consideration in Brazil, which may adversely impact our tax obligations.

Currently, there are different bills under discussion in the Brazilian Congress that seek to implement tax reforms, including proposals to modify the taxation applicable to legal entities.

On November 20, 2023, Constitutional Amendment No. 132 was approved, which instituted the consumption tax reform, amending the Brazilian tax system. Among the main changes brought about by the Constitutional Amendment No. 132/2023 is the unification of certain taxes: (a) Tax on Services and Tax on the Circulation of Goods and Services are unified in the form of the Tax on Goods and Services, and (b) Contributions to the Social Integration Program and to the Social Security Financing and Tax on Industrialized Products are replaced by the Contribution on Goods and Services. The new system will be implemented over a period of seven years, from 2027 to 2033. However, regulations with respect to the modifications have yet to be finalized (i.e., the definition of applicable rates). We are closely monitoring the developments as they may impact our tax burden.

With regard to income taxation, the Brazilian government has been discussing possible changes in corporate tax rates as a way to balance the impact of a possible taxation of dividends, as well as other changes that may impact the tax burden applicable to legal entities. In recent years, the Brazilian government has presented some proposals to the Brazilian Congress related to the taxation of dividends and the prohibition of the deduction of interest on equity, among which are currently in progress: (i) Bill No. 2,337, dated June 25, 2021, which provides for changes in income taxation, such as the introduction of the taxation of dividends and the repeal of the deduction of interest on equity; (ii) Bill No. 4,258, dated August 31, 2023, which prohibits the deduction of interest on equity from the calculation basis of Corporate Income Tax and Social Contribution on Net Income; and (iii) Bill No. 4,921, of October 10, 2023, which provides for the levying of Withholding Income Tax on profits and dividends paid, credited, delivered, employed or remitted to beneficiaries, individuals or legal entities, resident or domiciled abroad.

Bills No. 4,258/2023 and No. 4,921/2023, recently presented, are in the initial stages of processing before the Chamber of Deputies and the Brazilian Senate, respectively. In turn, Bill No. 2,337/2021 was approved by the Chamber of Deputies on September 2, 2021 and is currently awaiting consideration by the Brazilian Senate. The proposal was evaluated by the Committees, and since April 19, 2023, it has been with the rapporteur of the legislative house. The approval of these bills depends on the legislative process, which includes evaluation, voting, vetoing and amendments, all carried out by the Brazilian Congress and the President of the Republic. It is not possible to determine, from the outset, which proposals will be effectively implemented and how they may impact our operations.

In addition, on December 15, 2023, the house of representatives also approved the bill to convert Provisional Measure No. 1,185/2023 into the Law No. 14,789/2023, which establishes a new system for the tax treatment of revenues arising from governmental subsidies at the federal level.

Moreover, Law No. 14,789/23 changed the tax system for the deduction of expenses with the payment of interest on net equity, by altering certain aspects of the formula for calculating such expenses and making it more restrictive than the previous rules. Law No. 14,789/2023 came into force as of January 1, 2024, bringing a relevant impact to taxpayers who benefit from subsidies for investment and funding.

The Brazilian tax authorities have frequently implemented changes to tax regimes that may affect us and ultimately the demand of our customers for the products we sell. These measures include changes in prevailing tax rates and enactment of taxes, both temporary and permanent. Some of these changes may increase our tax burden, which may increase the prices we charge for the products we sell, restrict our ability to do business in our existing markets and, therefore, materially adversely affect our results of operations. There can be no assurance that we will be able to maintain our projected cash flow and results of operations following any increases in Brazilian taxes that apply to us and our operations.

In addition, we currently receive certain tax benefits. There can be no assurance that these benefits will be maintained or renewed. Also, given the current Brazilian political and economic environment, there can be no assurance that the tax benefits we receive will not be judicially challenged as unconstitutional. If we are unable to renew our tax benefits, such benefits may be modified, limited, suspended, or revoked, which may adversely affect us. Moreover, certain tax laws may be subject to controversial interpretation by tax authorities. In the event that tax authorities interpret tax laws in a manner that is inconsistent with our interpretations, we may be adversely affected.

On December 21, 2023, the Brazilian House of Representatives approved a bill to create a Brazilian Greenhouse Gas Emissions Trading System. Subject to the approval of the bill by both houses of the Brazilian parliament, Karoon, which has facilities or sources that may emit greater than 10,000 tCO_2/e per year, is likely to be considered a regulated entity under the scope of the regulation, which may impose reporting and other requirements on us. Under the currently proposed rules, we would be required to acquire assets, which are also known as SBCE assets, through the trading system. These assets include Brazilian Emissions Quotas, which are similar to the European Union Emissions Trading System, and Verified Emission Reduction Certificates. A portion (which is not yet defined) of the Verified Emission Reduction Certificates could be originated from voluntary carbon credits that meet certain legal requirements. However, the implementation and timeline for a Brazilian carbon market remains uncertain. Moreover, the Brazilian government may adopt new or more stringent measures to address climate change and greenhouse gas emissions in the future, which could increase our costs, liabilities, or obligations, or restrict our ability to operate or expand our assets. See also "– Laws regulating greenhouse gas emissions could adversely affect the cost, manner and feasibility of doing business and demand for the oil and gas that we produce" and "Regulatory overview – Regulatory overview-Brazil – Carbon credits and the Brazilian Greenhouse Gas Emissions Trading System."

Furthermore, the Brazilian Chamber of Deputies is currently discussing Bill No. 182, of 2024, which, among other things, intends to regulate the federal taxation of carbon credits. According to the Bill, the gain arising from the sale of these assets will be subject to income tax in accordance with: (i) the tax regime applicable to the taxpayer, in the case of developers who initially issued such assets (i.e., the issuer), (ii) the taxation applicable to net gains, when earned in transactions carried out on stock, commodity and futures exchanges and in organized over-the-counter markets (i.e., trading), and (iii) the taxation applicable to capital gains, in other cases. Bill No. 182/2024 is still in the initial processing phase, so it is not possible to affirm whether such provisions will make up the final wording of the bill or if it will be approved by both houses of the Brazilian parliament.

Our business subjects us to potential liability from litigation, arbitration and regulatory action.

The nature of our operations subjects us to the risk of litigation and/or regulatory action based on alleged violations of law, particularly environmental protection and health and safety laws. We are party to a wide range of joint venture, commercial agreements, including agreements with critical third-party infrastructure providers, and other relationships, which may also lead to disputes that result in litigation or arbitration claims. As a listed company, we also face the risk of shareholder class actions relating to the adequacy of our disclosures.

Damages claimed under any litigation, arbitration, regulatory action, including shareholder class actions, may be material or may be indeterminate, and the outcome of such litigation, arbitration or regulatory action could materially and adversely affect our business, results of operations or financial position. Preparing for and participating in litigation, arbitration or regulatory proceedings may occupy significant management time and distract management from their focus on our business. While we assess the merits of each lawsuit and defend ourselves accordingly, we may be required to incur significant expenses in defending against any such lawsuit and there can be no assurance that a court or tribunal will find in our favor. In addition, proceedings in which we are not directly subject may impact our business and operations.

We may also be involved in investigations, inquiries or disputes, debt recoveries, native title claims, pre-emptive right disputes, land tenure and access disputes, contractual claims with respect to our activities (including with suppliers, customers, joint venturers and parties engaged to construct and or develop our projects and infrastructure), environmental claims or occupational health and safety claims. Any of these claims or actions could result in delays, increase costs or otherwise adversely impact our assets and operations, financial performance and future financial prospects.

Similarly, one or more of our officers and directors may be defendants in judicial, administrative and/or arbitral proceedings, in civil, environmental, criminal, tax and/or labor matters. The commencement and/or the results of these proceedings may adversely affect our directors and officers, especially in cases of criminal proceedings, which may prevent them from exercising their corporate functions appropriately, causing adverse effects to our reputation, business or results of operations.

Our business, practices and policies are subject to risks associated with non-compliance with the Brazilian General Data Protection Law and could be adversely affected by the application of penalties, including fines and indemnifications.

Law No. 13,709/18, as amended by Law No. 13,853/2019, or the Brazilian General Data Protection Law, or LGPD, governs the processing of personal data in all economic sectors, and prescribes the rights of the data subjects, the legal bases applicable to the processing of personal data, the requirements for obtaining consent, the obligations and requirements relating to security incidents, breaches and data transfers, as well as authorization for the creation of the National Data Protection Authority, or ANPD, the government agency responsible for ensuring compliance with data protection standards and for applying sanctions in case of breach of the LGPD or security incidents.

If the measures we implement are considered insufficient by the ANPD to protect the personal data that we process or to maintain compliance with any requirement established by the LGPD, we may be subject to: (i) fines of up to 2% of the turnover of the legal entity or group in Brazil, limited to R$50 million (approximately US$10.3 million) per infraction, or other administrative penalties, (ii) obligations to repair damages to data subjects, clients or other business partners or providers and/or (iii) reputational damages, which could adversely affect our results of operations.

As the ANPD continues to release guidance on the implementation of LGPD obligations, the legal framework will evolve, and best practice examples will continue to emerge. In the event we are not in compliance with the LGPD, we and our subsidiaries may be subject to certain sanctions and we may be liable for material, moral, individual or collective damages, which could materially and adversely affect us. For further information, see "Regulatory overview – Regulatory overview – Brazil – Data protection and the Brazilian General Data Protection Law."

Risks Related to the Notes and Security

Our ability to generate cash depends on many factors beyond our control and we may not be able to generate sufficient cash to service all of our indebtedness, including the Notes, and to fund our working capital and capital expenditures, and may be forced to take other actions to satisfy our obligations under our indebtedness that may not be successful.

Our ability to pay principal and interest on the Notes and to satisfy our other debt obligations will depend upon, among other things:

- our future financial and operating performance (including the realization of any cost savings described herein), which will be affected by prevailing economic, industry and competitive conditions and financial, business, legislative, regulatory and other factors, many of which are beyond our control;

- our future ability to refinance or restructure our existing debt obligations, which depends on, among other things, the condition of the capital markets, our financial condition, and the terms of existing or future debt agreements; and

- our future ability to borrow under the RBL facility, the availability of which depends on, among other things, our complying with the covenants in the credit agreement governing such facility.

This will be affected by our ability to successfully implement our business strategy, as well as general economic, financial, competitive, regulatory and other factors beyond our control. We can provide no assurance that our business will generate cash flow from operations, or that we will be able to draw under the RBL facility or otherwise, in an amount sufficient to fund our liquidity needs, including the payment of principal and interest on the Notes.

If our cash flows and capital resources are insufficient to service our indebtedness, we may be forced to reduce or delay capital expenditures, sell assets, seek additional capital or restructure or refinance our indebtedness, including the Notes. These alternative measures may not be successful and may not permit us to meet our scheduled debt service obligations. Our ability to restructure or refinance our debt will depend on the condition of the capital markets and our financial condition at such time. Any refinancing of our debt could be at higher interest rates and may require us to comply with more onerous covenants, which could further restrict our business operations. In addition, the terms of existing or future debt agreements, including the instruments governing the RBL facility, may restrict us from adopting some of these alternatives. In the absence of such operating results and resources, we could face substantial liquidity problems and might be required to dispose of material assets or operations to meet our debt service and other obligations. We may not be able to consummate those dispositions for fair market value or at all. Furthermore, any proceeds that we could realize from any such dispositions may not be adequate to meet our debt service obligations then due. Our inability to generate sufficient cash flow to satisfy our debt obligations, or to refinance our indebtedness on commercially reasonable terms or at all, could result in a material adverse effect on our business, financial condition and results of operations and could negatively impact our ability to satisfy our obligations under the Notes.

If we cannot make scheduled payments on our indebtedness, we will be in default and lenders under the RBL facility could declare all outstanding principal and interest to be due and payable, the lenders under the RBL facility could terminate their commitments to loan money, our secured lenders could foreclose against the assets securing the indebtedness owing to them, and we could be forced into bankruptcy or liquidation. All of these events could cause you to lose all or part of your investment in the Notes.

If our indebtedness is accelerated, we may need to repay or refinance all or a portion of our indebtedness, including the Notes, before maturity. There can be no assurance that we will be able to obtain sufficient funds to enable us to repay or refinance our debt obligations on commercially reasonable terms, or at all.

If we default on our obligations to pay our other indebtedness, we may not be able to make payments on the Notes.

Any default under the agreements governing our indebtedness that are not waived by the required lenders and the remedies sought by the lenders of such indebtedness could leave us unable to pay principal, premium, if any, or interest on the Notes and could substantially decrease the market value of the Notes. In addition, the occurrence or continuance of any such default may result in us being prevented from undertaking transactions, exercising rights, or making payments, that would, in each case, be permitted in the absence of a default. If we are unable to generate sufficient cash flow and are otherwise unable to obtain funds necessary to meet required payments of principal, premium, if any, or interest on our indebtedness, or if we otherwise fail to comply with the various covenants, including financial and operating covenants, in the instruments governing our indebtedness (including the RBL facility), we could be in default under the terms of the agreements governing such indebtedness. In the event of such default, the holders of such indebtedness could elect to, among other things, (i) declare all the funds borrowed thereunder to be due and payable, together with accrued and unpaid interest, (ii) demand cash cover in connection with contingent exposures, (iii) terminate their commitments and cease making further loans and (iv) institute foreclosure or other enforcement proceedings against our assets, and we could be forced into bankruptcy or liquidation. Further, any foreclosure or other enforcement proceedings against our assets could breach the terms of our contracts or trigger changes of control, termination rights or other rights or remedies of our counterparties under our contracts, which may further materially and adversely affect our financial position and results of operation and our ability to satisfy our obligations under the Notes. See also "– It may be difficult to realize the value of the Collateral securing the Notes, which may result in holder of the Notes not receiving full payment of the obligations owed under the Notes following an event of default."

If our operating performance declines, we may in the future need to seek waivers from the required lenders under the RBL facility to avoid being in default. If we breach our covenants under the documents governing our indebtedness and seek a waiver, we may not be able to obtain a waiver from the required lenders, as applicable. If this occurs, we would be in default under the documents governing our indebtedness, the lenders could exercise their rights as described above, and we could be forced into bankruptcy or liquidation. See "Description of other financing arrangements" and "Description of the Notes."

The Issuer is a finance subsidiary of the Parent Guarantor that has no revenue generating operations of its own and will depend on cash from Karoon Energy to be able to make payments on the Notes.

The Issuer is a finance subsidiary of the Parent Guarantor with no business operations or subsidiaries and has limited assets and a limited ability to generate revenues. Following the offering of the Notes and the use of proceeds therefrom as described under "Use of proceeds," the Issuer's material liabilities will be the Notes. The Issuer will be dependent upon receiving funds from the Parent Guarantor and its other subsidiaries to meet its obligations, including its obligations under the Notes. If the Parent Guarantor's subsidiaries do not distribute cash to the Issuer to make scheduled payments on the Notes, the Issuer may not have any other source of funds that would allow it to make payments to holders of the Notes. The amounts available to the Issuer will depend on the profitability and cash flow of Karoon Energy. No assurance can be given that our Subsidiary Guarantors' cash flow from operations will be sufficient to fund the Issuer's repayment of the Notes.

Our subsidiaries may not be able to, or may not be permitted to, make distributions to enable us to make payments in respect of our indebtedness, including the Notes. Each of our subsidiaries is a distinct legal entity, and under certain circumstances legal and contractual restrictions (including the terms of the RBL facility) may limit our ability to obtain cash from them and we may be limited in our ability to cause any future joint ventures to distribute their earnings to us. In particular, distributions by Borrowing Base Obligors must be set out in the most recent liquidity statement delivered by us from time to time under the RBL facility. See "Description of other financing arrangements." Further, if the proportion of the borrowing base limit under the RBL facility attributable to development assets exceeds 35% of the total borrowing base limit, any such distribution by Borrowing Base Obligors is subject to approval of the majority lenders under the RBL facility. Applicable tax laws may also subject such payments to further taxation. While the indenture that will govern the Notes will limit the ability of our subsidiaries to incur consensual restrictions on their ability to pay dividends or make other intercompany payments to us, these limitations will not apply to existing restrictions and are subject to certain qualifications and exceptions. In the event that the Issuer and the Guarantors do not receive distributions from our subsidiaries, we may be unable to make required principal and interest payments on our indebtedness, including the Notes.

No assurance can be given that our subsidiaries' cash flow from operations will be sufficient to fund the Issuer's repayment of the Notes or the Guarantors' obligations under the Guarantees. In the event of an adverse change in the financial condition or cash flow generation of our subsidiaries, the Issuer and the Guarantors may not have sufficient funds to repay all amounts due on or with respect to the Notes, which would materially and adversely affect our financial position and results of operation and our ability to satisfy our obligations under the Notes.

The Notes will be structurally subordinated to all liabilities of our current and future non-Subsidiary Guarantor subsidiaries and junior to any of our future secured obligations that are secured by assets not constituting Collateral, to the extent of the value of the collateral securing such obligations.

The Notes will be structurally subordinated to indebtedness and other liabilities of our current and future subsidiaries that are not or will not be guaranteeing the Notes, and the claims of creditors of these subsidiaries, including trade creditors, will have priority as to the assets of these subsidiaries. In the event of a bankruptcy, liquidation or reorganization of any of our non-Subsidiary Guarantor subsidiaries, these non-Subsidiary Guarantor subsidiaries will pay the holders of their debts, holders of preferred equity interests and their trade creditors before they will be able to distribute any of their assets to us. The subsidiaries of the Parent Guarantor that will not guarantee the Notes on issuance have substantially no outstanding indebtedness, assets, liabilities, revenues or profits.

In addition, the indenture will permit non-Subsidiary Guarantor subsidiaries to incur additional indebtedness and will not contain any limitation on the amount of other liabilities, such as trade payables, that may be incurred by these subsidiaries.

The Notes will not be guaranteed by any of our subsidiaries that are not material or wholly owned. These non-Subsidiary Guarantor subsidiaries are separate and distinct legal entities and have no obligation, contingent or otherwise, to pay any amounts due pursuant to the Notes, or to make any funds available therefore, whether by dividends, loans, distributions or other payments. Any right that we or the Subsidiary Guarantors have to receive any assets of any of the non-Subsidiary Guarantor subsidiaries upon the liquidation or reorganization of those subsidiaries, and the consequent rights of holders of Notes to realize proceeds from the sale of any of those subsidiaries' assets, will be effectively subordinated to the claims of those subsidiaries' creditors, including trade creditors and holders of preferred equity interests of those subsidiaries.

Our obligations with respect to the Notes will be effectively junior to any of our future secured obligations with a security interest on assets not constituting Collateral, in each case, to the extent of the value of the collateral securing such obligations. Accordingly, the holders of the Notes may not be able to realize proceeds from assets not constituting Collateral.

If we classify subsidiaries as Unrestricted Subsidiaries, they will not be subject to any of the covenants in the indenture, and we may not be able to rely on the cash flow or assets of our Unrestricted Subsidiaries to pay the Notes or our other indebtedness.

While we currently have not designated any of our subsidiaries as Unrestricted Subsidiaries, we may classify certain of our wholly-owned subsidiaries as Unrestricted Subsidiaries in the future. Unrestricted Subsidiaries may not be subject to the covenants under the indenture. Unrestricted Subsidiaries may enter into financing arrangements that limit their ability to make loans or other payments to fund payments in respect of the Notes. Accordingly, we may not be able to rely on the cash flow or assets of our Unrestricted Subsidiaries to pay the Notes or any of our other indebtedness. In addition, the indenture will permit us to make significant investments in Unrestricted Subsidiaries.

Each Guarantor's liability under its Guarantee may be reduced to zero, avoided or released under certain circumstances, in which case you may not receive any payments from some or all of the Guarantors.

The creation and perfection of the security interests in respect of certain Collateral are governed by Australian, Brazilian, English and New York law. The laws relating to the creation and perfection of security interests in such non-U.S. jurisdictions differ from those in the United States and may be subject to restrictions and limitations, the effect of fraudulent conveyance and similar laws. These restrictions and limitations may have the effect of preventing, limiting and/or delaying the foreclosure and subsequent disposition of such Collateral, or reducing (including to zero) the amount recoverable thereunder, and may materially impair the claims of noteholders. Any such delay in having an enforceable claim could also diminish the value of the interest of the Noteholders in the Collateral due to, among other things, the existence of other potential creditors and claimants.

Additionally, the Guarantees by the Guarantors are limited to the maximum amount that such Guarantors are permitted to guarantee under applicable law. In addition, the Guarantees and indemnities, security and any subordination of the Guarantors may be limited in certain circumstances and by certain matters, including where the cost of providing such credit support is disproportionate to the benefit accruing to the beneficiaries (including, without limitation, tax consequences, notarization and perfection expenses), legal limitations, requirement and restrictions (including financial assistance, corporate benefit, capital maintenance rules, fraudulent preference, earnings stripping, controlled foreign corporation and thin capitalization rules, tax restrictions and similar principles), where providing such credit support would expose officers to risk of personal or criminal liability or where doing so would unduly disrupt our business. As a result, any such Guarantor's liability under its Guarantee could be reduced to zero, depending on the amount of other obligations of and particular circumstances pertaining to such Guarantor. Further, under the circumstances discussed more fully below, in particular with respect to KUSA Inc., a court under U.S. federal or state fraudulent conveyance and transfer statutes could avoid the obligations under a guarantee or further subordinate it to all other obligations of the Guarantor. See "– If the Issuer defaults on the Notes, or a Guarantor defaults on a Guarantee, your right to receive payments on the Notes or a Guarantee may be adversely affected by English, Australian, Brazilian or United States insolvency laws." In addition, the Subsidiary Guarantors will be automatically released from their Guarantees upon the occurrence of certain events, including the following:

- the designation of a Subsidiary Guarantor as an unrestricted subsidiary;
- a Subsidiary Guarantor ceasing to be a subsidiary as a result of any foreclosure of any pledge or security interest in favor of first-priority lien obligations or other exercises of remedies thereunder; or
- the sale or other disposition of our equity interests in a Subsidiary Guarantor or a holding company of a Subsidiary Guarantor.

If the Guarantee of any Subsidiary Guarantor is released, no holder of the Notes will have a claim as a creditor against that subsidiary, and the indebtedness and other liabilities, including trade payables and preferred equity interests, if any, whether secured or unsecured, of that subsidiary will be structurally senior to the claim of any holders of the Notes. See "Description of the Notes – Guarantees."

The ability of the Common Security Agents, for the benefit of the holders of the Notes to enforce the Collateral comprising our Brazilian concessions and shares of our Brazilian entities may be impaired by ANP regulatory qualification requirements for potential buyers. Any assignment of ownership of the emerging concession rights under the Concession Agreements, including if such assignment occurs as a consequence of the enforcement of the Concessions Collateral, will be subject to the prior authorization from ANP (or the federal government of Brazil), following the procedures set forth in ANP Resolution No. 785/2019. For the authorization process, ANP will assess the technical, economic and legal qualifications of the proposed assignee. Also, if the enforcement of the Collateral comprising shares of Brazilian entities results in a change of control of the relevant company(ies) that requires the replacement of the performance guarantee delivered to ANP by the relevant company(ies) with respect to their concessions and the performance guarantee is presented in relation to the current controller of the concessionaire, such change of control will result in an assignment of the concession rights, which will then be subject to the provisions of the concession assignment procedure established under ANP Resolution 785, described above. The ANP authorization procedure may take months to be concluded, which may cause the Collateral foreclosure process in connection with the Collateral comprising our Brazilian concessions (and the shares of our Brazilian entities, if applicable) to be lengthy and delay the recovery of funds by the holders of the Notes. In addition to such procedure, the concessionaire shall notify the ANP within 30 days after the registration of the corporate resolution that formalize the change of control of the company, in accordance with the terms of the ANP Resolution 785.

We may not be able to repurchase the Notes upon a change of control.

Upon the occurrence of certain specific kinds of change of control events, we will be required to offer to repurchase all of the outstanding Notes at 101% of the principal amount thereof plus, without duplication, accrued and unpaid interest to the date of repurchase. Additionally, under the RBL facility, a change of control constitutes a review event that may permit the lenders to accelerate the maturity of borrowings and terminate their commitments to lend. See "Description of other financing arrangements – Reserve based lending facility – Mandatory prepayment and review events." The source of funds for any repurchase of the Notes and repayment of borrowings under the RBL facility would be our available cash or cash generated from our subsidiaries' operations or other sources, including borrowings, sales of assets or sales of equity. It is possible that we will not have sufficient funds at the time of a change of control to make the required repurchase of Notes or that restrictions in our other debt documents will not allow such repurchases. We may require additional financing from third parties to fund any such repurchases, and we may be unable to obtain financing on satisfactory terms or at all. Further, our ability to repurchase the Notes may be limited by law. In addition, certain important corporate events, such as leveraged recapitalizations that would increase the level of our indebtedness, would not constitute a change of control under the indenture. See "Description of the Notes – Change of Control."

Courts interpreting change of control provisions under New York law (which will be the governing law of the indenture) have not provided clear and consistent meanings of such change of control provisions, which leads to subjective judicial interpretation. In addition, a court case in Delaware has questioned whether a change of control provision contained in an indenture could be unenforceable on public policy grounds. It is possible that a change of control will be deemed to occur under other indebtedness in circumstances where a change of control has not occurred under the indenture.

We may enter into transactions that would not constitute a change of control that could affect our ability to satisfy our obligations under the Notes.

Legal uncertainty regarding what constitutes a change of control and the provisions of the indenture may allow us to enter into transactions, such as acquisitions, refinancing or recapitalizations, that would not constitute a change of control but may increase our outstanding indebtedness or otherwise affect our ability to satisfy our obligations under the Notes. The definition of change of control for purposes of the Notes includes a phrase relating to the transfer of "all or substantially all" of our assets taken as a whole. Although there is a limited body of case law interpreting the phrase "substantially all," there is no precise established definition of the phrase under applicable law. Accordingly, your ability to require us to repurchase Notes as a result of a transfer of less than all of our assets to another person may be uncertain.

If the Issuer defaults on the Notes, or a Guarantor defaults on a Guarantee, your right to receive payments on the Notes or a Guarantee may be adversely affected by the laws of jurisdictions where our assets are located.

Bankruptcy, insolvency, administrative and other laws of jurisdictions where our assets are located may be materially different from, and subject to restrictions and limitations as compared to, the laws of jurisdictions with which you are familiar or which may be more favorable to your interests. Such differences may adversely affect your ability to enforce your rights under the Notes and the Guarantees. The Parent Guarantor and a number of the Guarantors are incorporated under the laws of Australia and, therefore, insolvency proceedings with respect to them would be likely to proceed under, and be governed by, Australian insolvency law. Karoon Petroleo & Gas Ltda is incorporated under the laws of Brazil and insolvency proceedings with respect to them may proceed under Brazilian law. The insolvency laws of Australia and Brazil are different from the insolvency laws of the United States. If we become insolvent, the treatment and ranking of holders of the Notes and of its other creditors and shareholders under Australian or Brazilian law may be different and less favorable than the resulting treatment and ranking if we were subject to the bankruptcy laws of the United States or other jurisdictions. Technicalities may undermine the ability of the holders of the Notes to directly participate or otherwise receive distributions in such insolvency proceedings. In addition, while none of the Guarantors is incorporated in England, certain of our security documents (including our intercreditor agreements) are governed by English law and certain of our assets are located in England or are contracts governed by English law. In the event of a bankruptcy, insolvency or similar event, proceedings could be initiated in any of these jurisdictions and/or the United States. Such multijurisdictional proceedings are likely to be complex and costly for creditors and otherwise may result in greater uncertainty and delay regarding the enforcement of your rights. There can also be no assurance that you will be able to effectively enforce your rights in such complex, multiple bankruptcy, insolvency or similar proceedings. See also "– If we become the subject of a bankruptcy proceeding, bankruptcy laws may limit your ability to realize value from the Collateral."

Under the provisions of Australian insolvency law, claims of secured creditors will, subject to certain exceptions as described below, rank ahead of claims of unsecured creditors in an insolvency process, and it will generally not be possible for the relevant Guarantors, the Issuer or other unsecured creditors to prevent or delay the secured creditors from enforcing their security to repay the debts due to them.

There are particular priority rules concerning "circulating assets", which typically encompass cash at bank (in un-blocked accounts), inventory and receivables. The claims of a secured creditor against circulating assets are by Australian insolvency law postponed to certain priority claims, including claims of employee creditors against the company, such as for wages, leave entitlements and redundancy payments. This can dilute the assets available to satisfy secured claims.

In addition, in Australia, certain claims of shareholders against the relevant company in a winding up are "subordinate claims," meaning that these claims will rank behind all other debts of, and claims against, the company by unsecured creditors. For example, in a winding-up, if shareholders were to claim damages against the debtor company, which claim is available to them in their capacity as a member of the company or arises from their buying, holding, selling or otherwise dealing in the shares of the debtor company (e.g., a claim for misleading and deceptive conduct), the payment of any amounts to shareholders claiming in this way would be deferred until all other non-shareholder creditor claims have first been satisfied. This statutory subordination, however, does not apply to claims of shareholders in a non-member capacity, for example, as a lender under a loan to an insolvent debtor company (there is no doctrine of equitable subordination recognized in Australia). In 2017, the Australian government passed reforms to Australian insolvency laws, including the introduction of an "ipso facto" moratorium. The legislation provides that enforcement of certain rights against a company under a contract, agreement or arrangement (such as a right entitling a creditor to terminate the contract or to accelerate payments or providing for automatic acceleration) are stayed for a certain period of time (and in some cases indefinitely), if the right arises for the reason that the corporation is in voluntary administration, or a managing controller is appointed to it, or it is, or announces that it will be applying to be, subject to a creditors' scheme of arrangement, or that relates to the company's financial position during any of those proceedings. The specified proceedings do not include liquidation. The ipso facto regime came into effect in Australia in 2018, and applies to ipso facto rights arising under contracts, agreements or arrangements entered into after July 1, 2018, subject to certain exclusions. In 2018, the Australian federal government also introduced regulations setting out the types of contracts and contractual rights which will be excluded from the stay. These regulations provide, among other things, that any ipso facto rights under a contract, agreement or arrangement that is or governs securities, financial products, bonds or promissory notes will be exempt from the moratorium. Furthermore, a contract, agreement or arrangement under which a party is or may be liable to subscribe for, or to procure subscribers for, securities, financial products, bonds or promissory notes is also excluded from the stay. Accordingly, these regulations should exclude the Notes and certain other related arrangements from the stay. However, since their commencement in 2018, the legislation and the regulations have rarely been the subject of judicial interpretation. If the regulations are determined not to exclude the Notes or related arrangements from their operation under the exclusions mentioned above or any other exclusion under the regulations, this may render the "ipso facto" provisions of the Notes or related arrangements unenforceable in Australia.

Brazilian law allows the granting of guarantees of notes, such as the Guarantees, but in the event that any Brazilian Guarantor files for judicial reorganization proceedings or bankruptcy, any debts owed to creditors (existing at the time of the filing) will be subject to such insolvency proceeding.

Brazilian bankruptcy law provides for three types of insolvency proceedings: judicial reorganization (recuperação judicial), which is an in-court voluntary reorganization, extrajudicial reorganization (*recuperação extrajudicial*), which is voluntary reorganization that is a form of "pre-pack" arrangement that is submitted to court confirmation to bind a dissenting or absent minority, and bankruptcy liquidation (- *falência*), which may be either voluntary or involuntary. In these cases, a creditor may be impaired to enforce its collateral in case it is subject to the proceeding, which is the case of pledges and mortgages in judicial reorganizations and may be the case in extrajudicial reorganizations as well (depending on the conditions proposed by the debtor to restructure its indebtedness). These types of collateral are not bankruptcy-remote and the relevant creditor may be subject to the proceeding and, therefore, paid either in the terms of the reorganization plan (in a judicial or extrajudicial reorganization scenario), or in the order established by the Brazilian bankruptcy law (in a bankruptcy liquidation scenario). Pursuant to Brazilian bankruptcy law, fiduciary liens over movable or immovable assets or fiduciary assignment of receivables or rights are bankruptcy-remote up to the value of Collateral and any balance not covered by the Collateral may be considered as unsecured credit, and, therefore, subject to the proceeding. However, in some circumstances, Brazilian courts have impaired creditors' ability to seizure and sell the collateral granted as fiduciary lien (either in a legal proceeding predicated on a default under the Notes and the Guarantees or during the stay period in a judicial reorganization proceeding), if such collateral is deemed essential to the continuation of the borrower's operations and business activities. A legal proceeding of this nature may last for several years. If the court accepts such defense in a legal proceeding against us outside of the context of a judicial reorganization (which is less common), we will have to post a bond to secure such legal proceeding consisting on other assets. We may not have other assets in sufficient value to offer in lieu of the Collateral. In a judicial reorganization proceeding, payment obligations under the Notes would not be included in the restructuring plan to the extent that they are fully secured by the Brazilian Share Collateral, as a fiduciary lien, and if the Judicial Reorganization Court considers the Brazilian Share Collateral essential to the maintenance of the debtor's activities, the holders of the Notes may not be able to enforce their rights in the Collateral governed by Brazilian law during the stay period, which lasts, according to the Brazilian bankruptcy laws, for 180 days, from the granting of the process of the judicial reorganization, and may be extended once for an equal period, on an exceptional basis, provided that the debtor has not caused the overcoming such term. Also, we cannot assure you that you would be successful in excluding the Collateral property subject to Brazilian Share Collateral agreements from the assets affected by insolvency proceedings.

Our variable rate indebtedness subjects us to interest rate risk, which could cause our debt service obligations to increase significantly.

Our borrowings under our RBL facility bear interest at a rate based on SOFR plus a margin, adjusted each interest period. We may incur additional indebtedness in future at floating interest rates. Interest rates could rise significantly in the future, thereby increasing our interest expenses associated with these obligations, reducing cash flow available for capital investments and limiting our ability to make payments on the Notes. We do not currently hedge our exposure to floating interest rates. If we decide to in the future, hedging may not be available or continue to be available on commercially reasonable terms. In addition, hedging itself carries certain risks, including that we may need to pay a significant amount (including costs) to terminate any hedging arrangements.

As of December 31, 2023, we had no interest rate hedging in place. In the future we may enter into interest rate swaps to reduce interest rate volatility. However any such swaps may not fully mitigate our interest rate risk, may prove disadvantageous, or may create additional risks. As of December 31, 2023, assuming our RBL facility was fully drawn, each 1% change in interest rates would result in a US$3,447,222 change in annual interest expense on such indebtedness.

Our fixed rate debt, including the Notes, does not expose us to the risk of increased interest payments as a result of changes in interest rates; however if interest rates rise significantly, we may find it difficult to raise new debt to refinance our debt ahead of its maturity.

There are restrictions on your ability to transfer or resell the Notes without registration or the filing of a prospectus under applicable securities laws.

We have not registered the Notes or the related Guarantees under the Securities Act or any state securities laws, and we do not currently intend to register the Notes. The holders of the Notes will not be entitled to require us to register the Notes for resale or otherwise. Neither the Notes nor the related Guarantees may be offered or sold in the United States, unless they are registered or the offer or sale is made pursuant to an exemption from registration under the Securities Act and applicable state securities laws. As a result, the transferability of the Notes may be negatively affected and you may be required to bear the risk of your investment for an indefinite period of time. By receiving the Notes, you will be deemed to have made certain acknowledgments, representations and agreements as set forth under "Notice to Investors."

Your ability to transfer the Notes may be limited by the absence of an active trading market, and there is no assurance that any active trading market will develop, or if developed be maintained, for the Notes.

The Notes are a new issue of securities for which there is no established public trading market, and we cannot assure you that in the future a market for the Notes will develop or that you will be able to sell the Notes that you have purchased. Although an application will be made for the listing and quotation of the Notes on the SGX-ST, we cannot assure investors that this application will be accepted. Affiliates of the initial purchasers have advised us that they intend to make a market in the Notes, if issued, as permitted by applicable laws and regulations, but they are not obligated to make a market in any of the Notes, and they may discontinue their market making activities at any time without notice. As a result, you cannot be sure that an active trading market will develop for the Notes. The liquidity of any market for the Notes will depend upon the number of holders of the Notes, our performance, the market for similar securities, the interest of securities dealers in making a market in the Notes and other factors. A liquid trading market may not develop for the Notes. If an active market does not develop or is not maintained, the price and liquidity of the Notes may be materially and adversely affected. Historically, the market for non-investment grade debt, such as the Notes, has been subject to disruptions that have caused substantial price volatility. We cannot assure you that if a market for the Notes were to develop, such a market would not be subject to similar disruptions. In addition, the Notes may trade at a discount from their value on the date you acquired the Notes, depending upon prevailing interest rates, the market for similar notes, our performance and other factors.

We may be unable to repay or repurchase the Notes at their maturity.

At the Notes' maturity, the entire outstanding principal amount of the Notes, together with accrued and unpaid interest, if any, will become due and payable. We may not have the funds to fulfill these obligations or the ability to renegotiate these obligations. If, upon the maturity date, other arrangements prohibit us from repaying the Notes, we could try to obtain waivers of such prohibitions from the lenders and holders under those arrangements, or we could attempt to refinance the borrowings that contain the restrictions. In these circumstances, if we were not able to obtain such waivers or refinance these borrowings, we would be unable to repay the Notes.

It may be difficult to realize the value of the Collateral, which may result in holder of the Notes not receiving full payment of the obligations owed under the Notes following an event of default.

The Collateral will be subject to any and all exceptions, materiality thresholds, defects, encumbrances, liens and other imperfections as may be specified in or permitted under the terms of the documents governing the security or otherwise accepted by the Trustee for the Notes and the Common Security Agents and any other creditors that have the benefit of first-priority liens on the Collateral, such as obligations under the RBL facility, from time to time, whether on or after the date the Notes are issued. The existence of any such exceptions, defects, encumbrances, liens and other imperfections could materially and adversely affect the value of the Collateral as well as the ability of the Common Security Agents to realize or foreclose on the Collateral.

The value of the Collateral at any time will depend on market and other economic conditions, including the availability of suitable buyers. No appraisals of any of the Collateral have been or will be prepared by us or on behalf of us in connection with this offering. By their nature, some or all of the pledged assets may be illiquid and may have no readily ascertainable market value. We cannot assure you that the fair market value of the Collateral as of the date of this offering memorandum equals or exceeds the principal amount of the debt secured thereby. The value of the assets pledged as Collateral could be impaired in the future as a result of changing economic conditions, our failure to implement our business strategy, competition, unforeseen liabilities and other future events. Accordingly, there may not be sufficient Collateral to pay all or any of the amounts due on the Notes and the RBL facility (and any additional future first-priority or pari passu second-priority obligations). Any claim for the difference between the amount, if any, realized by holders of the Notes from the sale of the Collateral and the RBL facility (and any additional future first-priority or pari passu second-priority obligations) will rank equally in right of payment with all of our other unsecured unsubordinated indebtedness and other obligations, including trade payables. Additionally, in the event that a bankruptcy case is commenced by or against us, if the value of the Collateral is less than the amount of principal and accrued and unpaid interest on the Notes and all other senior secured obligations, interest may cease to accrue on the Notes from and after the date the bankruptcy petition is filed and you will not be entitled to adequate protection of any such under-secured amount.

Pursuant to the Senior Lien Intercreditor Documents, any holders of indebtedness secured by first-priority liens in the Collateral, such as the lenders under the RBL facility, would direct any actions that may be taken in respect of the Collateral (including to commence and control enforcement proceedings against the Collateral and in connection with a restructuring) and, subject to certain exceptions, amendments or waivers of, or consents under, the security documents (provided that any such amendments, waivers or consents which relate to the nature or scope of the Collateral, the manner in which the proceeds of enforcement of the liens over the Collateral are applied or the release of the liens over the Collateral, shall, except as otherwise permitted or required by the Senior Lien Intercreditor Documents, the security documents or any applicable agreed security principles, require the approval of the Trustee for the Notes and the representative of each other secured creditor class under the Senior Lien Intercreditor Documents). The holders of indebtedness secured by first-priority liens are under no obligation to take into account the interests of the holders of the Notes and the Guarantees when determining whether and how to exercise their rights with respect to the Collateral, subject to the Senior Lien Intercreditor Documents, and their interest and rights may be significantly different from or adverse to yours. See "– Your right to exercise remedies with respect to the Collateral will be governed by, and materially limited by, the Senior Lien Intercreditor Documents."

The security interest of the Common Security Agents will be subject to practical challenges generally associated with the realization of security interests in Collateral. For example, the Common Security Agents may need to obtain the consent of a third party to obtain or enforce a security interest in a contract (including, without limitation, because taking or enforcing security could breach the terms of our contracts or trigger changes of control, termination rights or other rights or remedies of our counterparties under our contracts). We cannot assure you that the Common Security Agents will be able to obtain any such consent. We also cannot assure you that the consents of any third parties will be given when required to facilitate a foreclosure on such assets. Accordingly, the Common Security Agents may not have the ability to foreclose upon those assets and the value of the Collateral may significantly decrease.

In addition, the Collateral will be subject to liens permitted under the terms of the indenture, whether arising on or after the date the Notes are issued. The existence of any permitted liens could materially and adversely affect the value of the Collateral, as well as the ability of the Common Security Agents to realize or foreclose on the Collateral. Furthermore, not all of the Issuer's, the Parent Guarantor's and the Subsidiary Guarantors' assets secure the Notes, and those assets that do secure the Notes may be subject to customary exceptions and materiality thresholds. See "Description of the Notes – Security."

In particular, security over the assets of Guarantors other than Borrowing Base Obligors will be limited to the equity interests in Subsidiary Guarantors and wholly-owned material Subsidiaries, material intra-group receivables and material operating bank accounts, and where customary, a floating general security (or equivalent) over other assets of the Subsidiary Guarantors.

The Collateral will not include, among other things:

- in respect of U.S. obligors or assets located in the U.S., certain real property and leasehold interests in real property;
- in respect of U.S. obligors or assets located in the U.S., motor vehicles and other assets subject to certificate of title statutes and certain commercial tort claims;

- those assets over which the pledging or granting of security interests in such assets would be prohibited by applicable law, rule, regulation or contractual obligations (including leases, licenses or other agreements, government licenses or state or local license, franchises, charters or authorizations);

- certain bank accounts, including payroll and other employee wage and benefit accounts, tax accounts, contractual escrow accounts and fiduciary or trust accounts;

- goods (including inventory), moveable plant, equipment, vehicles or receivables if it would require labelling, segregation, periodic listing, notification, mapping or specification;

- in respect of U.S. obligors or assets located in the U.S., "intent-to-use" trademark applications until an amendment to allege use or statement of use has been filed;

- in respect of U.S. obligors or assets located in the U.S., margin stock; or

- certain other limited assets.

Our obligations to create and/or perfect security over our assets is also subject to other principles and restrictions. See "– Description of the Notes – Security – Limitation on Securities Collateral."

Some of these assets may be material to us and such exclusion could have a material adverse effect on the value of the Collateral.

Delivery of security interests in Collateral, which will be the case with respect to security granted over the Who Dat assets by KUSA Inc., as Guarantor of the Notes, or any Guarantees after the Issue Date increases the risk that the security interests or such Guarantees could be avoidable in bankruptcy.

Certain Collateral will be secured after the Issue Date of the Notes. For example, our subsidiary KUSA Inc., through which we hold our interest in the Who Dat, Dome Patrol and Abilene oil and gas assets, will not become a Borrowing Base Obligor until after the Issue Date, as it will only be a Corporate Guarantor on the Issue Date, and will grant security with respect to such assets at the same time as it grants security under the RBL facility. This will also apply with respect to future security interests granted in connection with the accession of further subsidiaries (if any) as additional Guarantors and the granting of security interests over their relevant assets and equity interests for the benefit of holders of the Notes and other secured parties under the Senior Lien Intercreditor Documents. Similarly, any Subsidiaries that are not Subsidiary Guarantors but are required under the RBL facility to become Subsidiary Guarantors in the future will be required to accede as guarantors not later than 90 days after the date we are required to deliver a compliance certificate under the RBL facility with respect to our financial statements (however the lenders of the agent under the RBL facility may choose to extend this date). The indenture will provide that the Parent Guarantor will cause its future wholly-owned subsidiaries that incur or guarantee certain debt (including the RBL facility) to accede to the Notes as Subsidiary Guarantors and execute and deliver a joinder to the security documents, and, to the extent required under the respective terms, a joinder agreement to any applicable security document and intercreditor agreements, in each case within 60 days of the date on which such future wholly-owned subsidiaries guaranteed such debt. However, the holders of the Notes will not have any control over when entities accede as guarantors and provide security for the benefit of the noteholders.

The granting of security interests to secure the Notes and the Guarantees may create hardening periods for such security interests in certain jurisdictions, including Australia, Brazil, the United States and England and Wales. The granting of shared security interests to secure future indebtedness permitted to be secured on the Collateral may restart or reopen such hardening periods in particular, as the Senior Lien Intercreditor Documents and the indenture will permit the release and retaking of security granted in favor of the relevant Notes in certain circumstances including in connection with the incurrence of future indebtedness. The applicable hardening period for these new security interests can run from the moment each new security interest has been granted, perfected or recreated. If the security interest granted, perfected or re-created were to be enforced before the end of the respective hardening period applicable in such jurisdiction, it may be declared void or ineffective and/or it may not be possible to enforce it. If the grantor of such security interest were to become subject to a bankruptcy or winding up proceeding after the Issue Date, any security interest in Collateral delivered after the Issue Date would face a greater risk than security interests in place on the Issue Date of being avoided by the grantor or by its trustee, receiver, liquidator, administrator or similar authority, or otherwise set aside by a court, as a preference under insolvency law. In Brazil, the declaration of bankruptcy should set the clawback period, which, in theory, must not be retroactive to more than 90 days prior to (i) the filing for bankruptcy; (ii) the filing for judicial reorganization; or (iii) the first protest of a title/bond issued by the company. The clawback period is a period during which certain transactions carried out by the bankrupt company may be revoked, such as: (i) the payment of debts not yet due by the debtor; (ii) the payment of debts that are due and payable by any means other than those specified in the contract; and (iii) the granting of a real property rights to secure a debt incurred prior to the clawback period. To the extent that the grant of any security interest is voided, holders of the Notes will lose the benefit of the security interest and may be required to disgorge prior payments or recoveries.

In particular and without limiting the foregoing, if the grantor of such security interest or a Guarantor were to become subject to a bankruptcy case under the U.S. Bankruptcy Code after the Issue Date of the Notes, any security interest in other Collateral, or any Guarantees delivered after the Issue Date of the Notes, would face a greater risk than security interests or Guarantees in place on the Issue Date (or with 30 days thereof) of being avoided by the pledgor or Guarantor (as debtor in possession) or by its trustee in bankruptcy or potentially by other creditors as a preference under the U.S. Bankruptcy Code if certain events or circumstances exist or occur. Specifically, security interests or Guarantees issued after the Issue Date (or within 30 days thereof) of the Notes may be treated under the U.S. Bankruptcy Code as if they were delivered to secure or guarantee previously existing or "antecedent" indebtedness. Any future pledge of Collateral or future issuance of a Guarantee in favor of the holders of the Notes, including pursuant to security documents or Guarantees delivered in connection therewith after the date the Notes are issued, may be avoidable as a preference if, among other circumstances, (i) the applicable pledgor or Guarantor is insolvent at the time of the pledge or the issuance of the Guarantee, (ii) the pledge or the issuance of the Guarantee permits the holders of the Notes to receive a greater recovery in a hypothetical chapter 7 case than if the pledge or Guarantee had not been given, and (iii) a bankruptcy case in respect of the applicable pledgor or Guarantor is commenced within 90 days following the pledge or the perfection thereof or the issuance of the Guarantee (as applicable), or, in certain circumstances, a year. Accordingly, if we or any Guarantor were to file for bankruptcy protection after the Issue Date of the Notes and (1) any liens not granted on the Issue Date of the Notes had been perfected, or (2) any Guarantees not issued on the Issue Date of the Notes (as applicable) had been issued, less than 90 days before commencement of such bankruptcy case (or, if applicable, one year), such liens or Guarantees are more likely to be avoided as a preference by the bankruptcy court than if delivered and promptly recorded on the Issue Date of the Notes (even if the liens perfected or other Guarantees issued on the Issue Date (or within 30 days thereof) of the Notes would no longer be subject to such risk). To the extent that the grant of any such security interest and/or Guarantee is avoided as a preference or otherwise, you would lose the benefit of the security interest and/or Guarantee (as applicable) and may be required to return prior payments.

Rights in the Collateral may be materially and adversely affected by the failure to perfect security interests in Collateral now or in the future.

Applicable law provides that a security interest in certain tangible and intangible assets can only be properly perfected and its priority retained through certain actions undertaken by the secured party, the Issuer or relevant Guarantor and/or third parties such as contractual counterparties, banks or other institutions with whom deposit accounts or other assets are held or other third parties. The liens in the Collateral securing the Notes may not be perfected with respect to the claims of the Notes if the Common Security Agents, the Issuer or any such Guarantor, or any third party, as applicable, are not able to, or do not, take the actions necessary to perfect any of these liens. We and the Guarantors have limited obligations to perfect the Noteholders' security interest in specified Collateral (including, without limitation, if it would restrict our ability to conduct our operations and business in the ordinary course or as otherwise permitted). Applicable third parties generally will not be obliged to take action to assist in perfection of security. In addition, applicable law provides that certain property and rights acquired after the grant of a general security interest, such as real property, certain intellectual property and certain proceeds, can only be perfected at the time such property and rights are acquired and identified.

Under Brazilian law, the perfection of security interests over assets depends on certain registration requirements to be considered existent, valid and/or binding, as applicable. Depending on the assets over which the security interest is to be created, (a) the signature of the parties who sign the relevant security agreements outside Brazil must be notarized by a public notary licensed pursuant to the laws of the place of signature and the signature of such public notary must be authenticated by the Brazilian Consulate with jurisdiction over the place of execution, except when such public notary is from a country that is signatory of the Hague Convention Abolishing the Requirement of Legalization for Foreign Public Documents dated as of October 5, 1961, in which case it must be duly apostilled by the applicable foreign authority (and the authentication by a Brazilian Consulate is not required); (b) the relevant security agreement must be translated into Portuguese by a sworn translator (tradutor juramentado) in Brazil; and (c) the relevant security agreement and the sworn translation thereof must be registered with the appropriate Registry of Deeds and Documents (Cartório de Registro de Títulos e Documentos) and/or Real Estate Registry (Cartório de Registro Geral de Imóveis), as applicable, in Brazil. In case the relevant security agreement is signed electronically, no such notarization or apostille mentioned in item (a) above will apply, but its sworn translation and registration of the document with the appropriate Registry of Deeds and Documents (Cartório de Registro de Títulos e Documentos) and/or Real Estate Registry (Cartório de Registro Geral de Imóveis), as applicable, will still be required. In relation to the registrations with the applicable Registry of Titles and Deeds, Brazilian law was recently changed. Previously, the effects of the registration would be retroactive to the date of the agreement if such agreement was filed for registration within 20 days of its date; however, the law now states that the effects of the registration will no longer be retroactive and shall only be effective from the date of registration onwards. In the event of a failure to create and perfect liens on the Collateral, including by making such registrations, the Notes will not be secured by such assets.

Note that, in case of electronic signatures in Brazil, the electronic certification needs to be recognized by the Brazilian system of digital certification (known as "ICP-Brasil"). Certain notary offices are more flexible and accept foreign certification companies, provided that they meet certain requirements. However, considering that most notary offices have shown little to no flexibility, a more conservative approach is generally adopted to require signatories to obtain a certification validated by ICP-Brasil.

In addition to the above, in Brazil, the perfection of security interests over certain assets may require additional formalities. In relation to the Brazilian Security Documents, the following additional formalities are required: (i) the registration of the relevant liens in the company's articles of association, in relation to the fiduciary assignment over the quotas issued by the company's Brazilian subsidiary; (ii) giving of notice to ANP informing it of the inclusion of the noteholders as secured parties under the pledge of concessions, within 30 days after the execution of the relevant amendment to the pledge of concessions; and (iii) delivery of notices and obtaining consents, as applicable, from the counterparties to the conditional Assignment and Fiduciary Assignment of Credit Rights Agreement. Under the current wording of the Conditional Assignment and Fiduciary Assignment of Credit Rights Agreement, the Company must use reasonable efforts to obtain such consents, but the Collateral over such assigned agreements and assigned credit rights that require such consents will not be perfected until such consents are duly obtained. Therefore, the Notes will not be secured by any assets, perfection over which requires consents to be obtained, until such consents are obtained.

With respect to Australia, the granting of security interests over personal property is generally governed by the Personal Property Securities Act 2009 (the "PPSA"). The creation, perfection and/or priority of security over assets which are not subject to the PPSA (including, without limitation, interests in real property), is typically subject to other requirements and formalities under applicable laws of the relevant State and or Territory of Australia or, as applicable, federal law. We have limited obligations to create, perfect or preserve the priority of security interests in such assets. See "Description of the Notes – Security – Limitation on Securities Collateral."

Under the provisions of the PPSA, security interests that are unperfected at the time of the appointment of a voluntary administrator or the occurrence of certain other insolvency events in relation to the relevant grantor of such security interest will, in accordance with the rules set out in Part 8.2 (*Vesting of certain unperfected security interests*) of the PPSA, automatically vest in the grantor upon the appointment of the voluntary administrator or the occurrence of the relevant insolvency event. The secured party will lose its security interest in the applicable collateral as a result and can only assert an unsecured claim against the relevant grantor.

In order to prevent the security interest from vesting in the grantor on the applicable insolvency event, a security interest must be perfected in accordance with the provisions of the PPSA. Perfection can only be achieved once the security interest is enforceable against the grantor (known as attachment) and against third parties (including by execution of a security agreement). The most common method of perfection is by registration of the security interest on the Personal Property Securities Register. Where the grantor is a company, there are time limits for registration. For example, security interests that were not perfected within 20 business days after the relevant security agreement came into force (subject to limited exceptions) will vest in the company upon the appointment of the voluntary administrator or the occurrence of other applicable insolvency events. Other methods of perfection include taking possession or control of the collateral (in each case in accordance with the PPSA). Those methods of perfection are only available in relation to specific types of property, the most common example being financial property, such as shares, units and bonds and certain bank accounts. Perfection by possession or control can be lost if, for example, a secured party ceases to have control of collateral (and did not also have a valid registration in respect of the security interest).

The Common Security Agents will not monitor and has no obligation to monitor, and there can be no assurance that we will inform the Common Security Agents of, the future acquisition of property and rights that constitute Collateral, and that the necessary action will be taken to properly perfect the security interest in such after-acquired Collateral. Such failure may result in the loss of the security interest in the Collateral or the priority of the security interest in favor of the Common Security Agents, as applicable, against third parties and the holders of the Notes would not be entitled to the proceeds from the sale of all or any of the Collateral that is the subject of such failure or any other remedies in connection therewith. Even if the Common Security Agents do take all actions necessary to create properly-perfected security interests, any such security interests that are perfected after the date of the indenture would remain at risk of being avoided as a preferential transfer or otherwise in any bankruptcy even after the security interests perfected on the closing date were no longer subject to such risk.

In addition, even if the Common Security Agents do properly perfect liens on Collateral acquired in the future, such liens may (as described further herein) potentially be avoidable as a preference in any bankruptcy case under certain circumstances. See "– Delivery of security interests in Collateral, which will be the case with respect to security granted over the Who Dat assets by KUSA Inc., as Guarantor of the Notes, or any Guarantees after the Issue Date increases the risk that the security interests or such Guarantees could be avoidable in bankruptcy."

The security interests in the Collateral will be granted to the Common Security Agents rather than directly to the holders of the Notes.

The security interests in the Collateral that will secure our obligations under the Notes and the obligations of the Guarantors under the Guarantees will not be granted directly to the holders of the Notes but will be granted only in favor of the Common Security Agents (or their respective agents) for the benefit of all secured indebtedness under the Senior Lien Intercreditor Documents (including, without limitation, the RBL facility and the Notes). For the avoidance of doubt, where any reference is made to first-priority liens or second-priority liens (or any similar or analogous expressions), it includes a reference to the common security held by the Common Security Agents for the collective benefit of all secured parties (or more than once class of secured parties) securing the relevant secured debt in such order of priority. The ability of the Common Security Agents to perfect and/or enforce certain of the Collateral may be restricted by applicable law.

The indenture will provide that only the Common Security Agents have the right to enforce the security documents for the Notes. The ability of the holders of the Notes to instruct the Common Security Agents to enforce the security documents will be limited under the Senior Lien Intercreditor Documents and the Second Lien Intercreditor Agreement. See "– Indebtedness under the Notes will be subject to the Senior Lien Intercreditor Documents which provide that the RBL facility and other certain future first-priority indebtedness will be senior to the Notes to the extent of the value of the Collateral securing those obligations."

As a consequence, holders of the Notes will not have direct security interests and will not be entitled to take enforcement action in respect of the Collateral, except through the Common Security Agents and may only instruct the Common Security Agents to take enforcement action to the extent provided in the Senior Lien Intercreditor Documents.

There are circumstances other than repayment or discharge of the Notes under which the Collateral will be released automatically, without your consent or the consent of the Trustee.

Under various circumstances, Collateral will be released automatically, including:

- a sale, transfer or other disposition of such Collateral (including to the Issuer, the Parent Guarantor or a Subsidiary Guarantor but without prejudice to any obligation of any Group member to provide replacement security) in a transaction not prohibited under the indenture;

- with respect to Collateral held by the Parent Guarantor or a Subsidiary Guarantor, upon the release of the Parent Guarantor or such Subsidiary Guarantor from its Guarantee, as applicable;

- with respect to Collateral held by the Issuer, upon the release or discharge of the Issuer's obligations under the Notes pursuant to the indenture;

- pursuant to the Senior Lien Intercreditor Documents with respect to enforcement actions by the holders of the first-priority obligations;

- pursuant to the Second Lien Intercreditor Agreement with respect to enforcement actions by the holders of the then-controlling second-priority obligations; and

- if the Notes have been discharged or defeased pursuant to a legal defeasance or covenant defeasance under the indenture.

The Guarantee of a Subsidiary Guarantor or a holding company of such Subsidiary Guarantor will be automatically released to the extent it is released in connection with a sale of such Subsidiary Guarantor in a transaction not prohibited by the indenture. The indenture also permits us to designate one or more of our restricted subsidiaries that is a Subsidiary Guarantor of the Notes as an unrestricted subsidiary. If we designate a Subsidiary Guarantor as an unrestricted subsidiary for purposes of the indenture, all of the liens on any Collateral owned by such subsidiary or any of its subsidiaries and any Guarantees of the Notes by such subsidiary will be released under the indenture but not necessarily under the RBL facility and the aggregate value of the Collateral will be reduced. In addition, the creditors of the unrestricted subsidiary and its subsidiaries will have a claim on the assets of such unrestricted subsidiary and its subsidiaries that is senior to the claim of the holders of the Notes. See "– If we classify subsidiaries as Unrestricted Subsidiaries, they will not be subject to any of the covenants in the indenture, and we may not be able to rely on the cash flow or assets of our Unrestricted Subsidiaries to pay the Notes or our other indebtedness."

We will, in most cases, have control over the Collateral, and the sale of particular assets by us could reduce the pool of assets securing the Notes and the Guarantees.

The collateral documents relating to the liens over the Collateral will allow us to remain in possession of, retain exclusive control over, freely operate, and collect, invest and dispose of any income from, the Collateral. We may, therefore, among other things, without any release or consent by the Collateral Security Agents or the Trustee, conduct ordinary course activities with respect to Collateral permitted by the indenture and the Security Documents, such as selling, factoring, abandoning or otherwise disposing of Collateral and making ordinary course cash payments (including repayments of indebtedness), all of which could reduce the pool of assets securing the Notes. See "Description of the Notes – Security."

If we become the subject of a bankruptcy proceeding, bankruptcy laws may limit your ability to realize value from the Collateral.

The right of the Common Security Agents to foreclose upon, repossess, and dispose of the Collateral upon the occurrence and during the continuance of an event of default under the indenture is likely to be significantly impaired by applicable bankruptcy law if a bankruptcy case were to be commenced by or against us before the Common Security Agents repossessed and disposed of the Collateral (and sometimes even after). Upon the commencement of a case under the Title 11 of the United States Code (the "U.S. Bankruptcy Code"), a secured creditor such as the Common Security Agents is prohibited from repossessing its security from a debtor in a bankruptcy case, or from disposing of security previously repossessed from such debtor, without prior bankruptcy court approval, which may not be given or could be materially delayed. Moreover, the U.S. Bankruptcy Code permits the debtor to continue to retain and use collateral even though the debtor is in default under the applicable debt instruments, provided that the secured creditor is given "adequate protection." The meaning of the term "adequate protection" may vary according to circumstances, but it is intended in general to protect the value of the secured creditor's interest in the collateral as of the commencement of the bankruptcy case and may include cash payments or the granting of additional or replacement security or superpriority administrative expense claims if and at such times as the bankruptcy court in its discretion determines that the value of the secured creditor's interest in the collateral is declining during the pendency of the bankruptcy case. A bankruptcy court may determine that a secured creditor may not require compensation for any such diminution in the value of its collateral if the value of the collateral exceeds the debt it secures.

In view of the lack of a precise definition of the term "adequate protection" and the broad discretionary power of a bankruptcy court, it is impossible to predict:

- whether or when payments under the Notes could be made following the commencement of a bankruptcy case, or the length of any delay in making such payments;
- whether or when the Common Security Agents could repossess or dispose of the Collateral;
- the value of the Collateral at the time of the bankruptcy petition or any other relevant time; or
- whether or to what extent holders of the Notes would be compensated for any delay in payment or loss of value of the Collateral through the requirement of "adequate protection."

Any disposition of the Collateral during a bankruptcy case would also require permission from the bankruptcy court (which may not be given or could be materially delayed). Furthermore, in the event a bankruptcy court determines the value of the Collateral is not sufficient to repay all amounts due on debt which is to be paid first out of the proceeds of the Collateral, the holders of the Notes would hold a secured claim only to the extent of the value of the Collateral to which the holders of the Notes are entitled and unsecured "deficiency" claims with respect to any shortfall or under-collateralization. The U.S. Bankruptcy Code only permits the payment and accrual of post-petition interest, costs and attorneys' fees to a secured creditor during a debtor's bankruptcy case to the extent the value of its collateral is determined by the bankruptcy court to exceed the aggregate outstanding principal amount of the obligations secured by the collateral.

In Australia notwithstanding the statutory moratorium that applies on claims against a company for which a voluntary administrator is appointed, a secured creditor that holds a validly perfected security interest over the whole, or substantially the whole, of the company's property, will be permitted to enforce its security by appointing a receiver and manager to the company within 13 business days of the voluntary administrator's appointment. If this occurs, the secured creditor's receiver and manager will have control over the assets and undertaking of the company and can deal with the company's assets as directed by the secured creditor. If a secured creditor elects not to appoint a receiver and manager, or if the secured creditor does not have security over the whole or substantially the whole of the property of the company, the secured creditor will need to wait for the voluntary administration process to come to an end.

The voluntary administration regime provides a tight timetable for the holding of meetings of creditors and for reporting by the voluntary administrator to creditors on the available options for the company (usually either a winding up or a "work out" pursuant to a deed of company arrangement ("DOCA")). A DOCA will ordinarily provide for the company to make a distribution to creditors from a "deed fund" in exchange for the extinguishment and release of their claims against the company. Importantly, secured creditors with validly perfected security interests will not be bound by the terms of a DOCA if they do not vote in favor of it. For this reason, a DOCA is usually only proposed in circumstances where the secured creditors' interests are accommodated.

In the event that receivers and managers are appointed to the company to realize secured property in order to pay down secured debt, it is relevant to note that property of the company that is subject to a circulating security interest must be used by the receivers to pay certain priority creditor claims (including employee entitlements) before any amounts can be remitted to the secured creditor. There are equivalent statutory priorities in respect of property the subject of a circulating security interest in a liquidation context. Accordingly, if the secured property is insufficient to pay down priority claims as well as the claims of secured creditors (in accordance with any contractual priorities as between secured creditors), the secured debt may not be discharged in full.

In the event that a liquidator is appointed to a company, that liquidator has an obligation to maximize the pool of assets available to creditors and in order to achieve that, the liquidator is given broad statutory powers to set aside transactions entered into by the company in the lead up to its insolvency. The main classes of transactions include uncommercial transactions, unfair preferences, creditor-defeating transactions and unfair loans. A liquidator can also commence proceedings in the name of the company against its directors (for example, for breach of duties) or against third parties. Despite the appointment of a liquidator, a secured creditor with a validly perfected security interest may realize or otherwise deal with its secured property, and a liquidator cannot deal with secured property unless the relevant secured creditor surrenders its security.

In Brazil, the right and ability of the Common Security Agents, for the benefit of the holders of the Notes, to realize or foreclose on the Collateral upon the occurrence of an event of default is likely to be significantly impaired by applicable bankruptcy law if a judicial reorganization is filed by the debtor or a bankruptcy proceeding were to be commenced by or against us prior or during the foreclosure of the Collateral by the Common Security Agents. Under applicable bankruptcy law, in the case of a judicial reorganization, the creditors secured by fiduciary lien are not subject to the restructuring plan up to the limit of the collateral, which means that the foreclosure of the collateral is permitted, except during the stay period if the collateral is granted over assets that are deemed essential to the company's restructuring. In case of bankruptcy, the collateral would not be part of the bankrupt estate since ownership of the collateral would have been transferred to the creditor, or if the asset collateralized no longer exists when the bankruptcy is decreed, the creditor who holds the collateral must be repaid in cash (through a restitution proceeding). On the other hand, the mortgage and pledge collaterals are subject to the judicial reorganization and bankruptcy. Therefore, a mortgage/pledge cannot be enforced against a debtor under judicial reorganization or bankruptcy, and the creditor does not have the right to take possession of the asset given as collateral. However, in a judicial reorganization scenario, the creditor holding the mortgage/pledge is entitled to participate in the proceedings and vote on a restructuring plan. The confirmation of the judicial reorganization plan binds creditors secured by mortgage/pledge; however, the collateral over the asset can only be released with the consent of the creditor holding the collateral.

Certain of our assets may be located in, or subject to the laws of, jurisdictions other than the jurisdiction in which the applicable Guarantor is organized. Subject to limited exceptions, security will be governed by the laws of the jurisdiction in which the relevant Guarantor is organized, and we will not have to create or perfect security under local law over assets in other jurisdictions (however security over equity interests issued by a Guarantor will be governed by the laws of the issuer's jurisdiction and English law security has been granted over certain of our assets located in England, including bank accounts). See "Description of the Notes – Security – Limitation on Securities Collateral." Security under the laws of the Guarantor's jurisdiction may not be effective to create and/or perfect the security interests in assets located in any other jurisdiction. In addition, such assets may be subject to local laws which impair the effectiveness or priority of such security, your or the Common Security Agents' ability to enforce or otherwise exercise rights with respect to the applicable assets or your ability to participate in or otherwise receive distributions with respect to such assets. Further, proceedings could be initiated in multiple jurisdictions, and multijurisdictional proceedings are likely to be complex and costly for creditors and otherwise may result in greater uncertainty and delay regarding the enforcement of your rights. The impact of such principles and matters on the value of, and/or your ability to realize, the value of any such Collateral may be material.

Also, the Senior Lien Intercreditor Documents and the Second Lien Intercreditor Agreement will provide that, in the event of a bankruptcy by the Issuer or a Guarantor, the holders of the Notes will (and in the case of the Second Lien Intercreditor Agreement, may) be subject to certain restrictions with respect to their ability to object to a number of important matters or to take other actions following the filing of a bankruptcy petition with respect to the Collateral prior to (with respect to the Senior Lien Intercreditor Documents) the discharge of the obligations under the RBL facility and other first-priority secured obligations. In particular, the Senior Lien Intercreditor Documents will, and the Second Lien Intercreditor Agreement may, impose certain limitations on the holders of the Notes with respect to their rights to seek adequate protection with respect to the liens on the Collateral, to object to proposed debtor-in-possession financing or the use of cash Collateral that has been consented to by the holders of indebtedness subject to first-priority liens, such as the lenders under the RBL facility, or the Common Security Agents for the then-controlling second-priority obligations, or to raise certain objections to any sale of the Collateral that has been consented to by the holders of indebtedness subject to first-priority liens or the Common Security Agents for the then-controlling second-priority obligations. See "Description of the Notes – Security Documents – Senior Lien Intercreditor Documents" and "Description of the Notes – Security Documents – Second Lien Pari Passu Intercreditor Agreement."

The Collateral and related Guarantees may be diluted under certain circumstances.

The indenture, the RBL facility and any agreements governing our other indebtedness will permit us to incur additional secured indebtedness, including additional notes, parity lien obligations and other priority lien obligations, subject to our compliance with the restrictive covenants applicable to us at the time we incur such additional secured indebtedness. Such additional indebtedness may be secured by first-priority liens or senior-priority over the Collateral, or (including in the case of any additional notes issued under the indenture) by second-priority liens over the Collateral on a pari passu basis with the liens securing the indebtedness under the Notes. An issuance of any such additional indebtedness would therefore dilute the value of the Noteholders' rights to the Collateral.

The security interests of the noteholders in after-acquired assets may not be perfected in a timely manner or at all.

If additional restricted subsidiaries are formed or acquired and become Subsidiary Guarantors under the indenture, or additional assets are acquired by a Subsidiary Guarantor, additional security documents would be required to be entered into, additional financing statements would be required to be filed and/or other filings or steps would need to be made and/or other steps may need to be taken to create and/or perfect the security interest in the assets of such Subsidiary Guarantors. See "– Rights in the Collateral may be materially and adversely affected by the failure to perfect security interests in Collateral now or in the future." Depending on the type of the assets constituting after-acquired

Collateral, additional action may be required to be taken to create and/or perfect the security interest in such assets, such as the entry into of additional security documents, the delivery of physical Collateral, if permitted by the Senior Lien Intercreditor Documents, or the execution and recordation of mortgages or deeds of trust or the execution of amendments to the existing Security Documents to duly describe and detail the assets comprising the after-acquired collateral. Our obligations to take such steps are limited. See "Description of the Notes – Security – Limitation on Securities Collateral." Even if such additional actions are taken to perfect the security interest in such after- acquired Collateral, to the extent a security interest in any Collateral is not perfected on the Issue Date of the Notes, such security interest might be avoidable in bankruptcy as a preferential transfer or otherwise, which could impact the value of the Collateral. See "– Delivery of security interests in Collateral, which will be the case with respect to security granted over the Who Dat assets by KUSA Inc., as Guarantor of the Notes, or any Guarantees after the Issue Date increases the risk that the security interests or such Guarantees could be avoidable in bankruptcy" below.

Certain Collateral securing the Notes will not be in place until after the Issue Date.

The Issuer and KUSA Inc. will grant to the Common Security Agents for the benefit of the RBL facility, the holders of the Notes and other secured indebtedness from time to time the security described in " Description of the Notes – Security – U.S. Security" which does not include security over their interests in the Who Dat assets, except to the extent required to be provided by a Subsidiary Guarantor that is not a Borrowing Base Obligor. See "– It may be difficult to realize the value of the Collateral securing the Notes, which may result in a holder of the Notes not receiving full payment of the obligations owed under the Notes following an event of default." We intend to designate those interests as borrowing base assets under the RBL facility. Once they are so designated, KUSA Inc. will become a Borrowing Base Obligor (if it has not already become a Borrowing Base Obligor by becoming a borrower under the RBL facility) and, subject to relevant exceptions and limitations, will grant additional security over assets relating to Who Dat. Holders of the Notes will be secured on a second lien basis (subject to the security principles and applicable local law) over those assets. Until that designation occurs, holders of the Notes will only have the benefit of security over the Who Dat assets to the extent described in "Description of the Notes – Security – Limitations on securities collateral."

Security over certain assets constituting the Collateral on which security interest in favor of the Common Security Agents is required may not be perfected on the Issue Date.

Security interests over the Brazilian assets of the Borrowing Base Obligors constituting the Collateral, which will be required under the Indenture, may not be perfected on the Issue Date. To the extent such security interests are not perfected on such date, we will be required to deliver fully executed agreements to the Common Security Agent with respect to pledging and/or assigning such interests and to provide all necessary notifications by the Issue Date and have such security interests thereafter perfected within eight business days and twenty days, subject to extensions, in relation to, respectively, the security documents to be registered with Registry of Titles and and Deeds and with Real Estate Registry from the date of the execution of the relevant security documents, but there can be no assurance that such security interests will be perfected on a timely basis. See "Description of the Notes – Security – Brazilian security." In the event that significant time passes between the issuance of the Notes and the perfection of the security interests with respect to such assets, the validity of such security interests may be questioned in Brazilian insolvency proceedings. In a judicial reorganization, creditors are classified in four classes, depending on the nature of their credits, for the purpose of voting and receiving the payment, but there is no preference between one class and another. Creditors with *in rem* guarantees (pledge and mortgage) are subject to judicial reorganization and must be classified as secured creditors. Creditors secured by fiduciary liens, in turn, are not subject to the proceeding, which means that the holder of such liens can enforce the collateral. If a reorganization court determines that the collateral of a creditor (both *in rem* and/or fiduciary) is not valid, such creditor will be classified as an unsecured creditor in the judicial reorganization.

The waterfall of payments in bankruptcy is established by Brazilian bankruptcy law, and creditors with *in rem* guarantees have priority over unsecured creditors. Creditors holding fiduciary liens are also not subject to bankruptcy and must receive the asset object of the collateral as payment or the equivalent in cash. If a bankruptcy court determines that the collateral of a creditor (both *in rem* and/or fiduciary) is not valid, such creditor will be classified as an unsecured creditor in the judicial reorganization.

Additionally, our subsidiary KUSA Inc., through which we hold our interest in the Who Dat, Dome Patrol and Abilene oil and gas assets, will not become a Borrowing Base Obligor until after the Issue Date, as it will only be a Corporate Guarantor on the Issue Date, and will grant security with respect to such assets at the same time as it grants security under the RBL facility. Perfection of the security interests after the Issue Date materially increases the risk that the liens with respect to those interests could be avoided, in the event of a bankruptcy. See "– Delivery of security interests in Collateral or any Guarantees after the Issue Date, which will be the case with respect to security granted over the Who Dat assets by KUSA Inc., as guarantor of the Notes, increases the risk that the security interests or such Guarantees could be avoidable in bankruptcy" for further details regarding such consequences with respect to the U.S. Bankruptcy Code.

The Collateral is subject to casualty risks, which may limit your ability to recover as a secured creditor if there are losses to the Collateral and have an adverse impact on our operations and results.

We maintain insurance or otherwise insure against certain hazards. There are, however, losses that may not be insured. If there is a total or partial loss of any of the pledged Collateral, we cannot assure you that any insurance proceeds received by us will be sufficient to satisfy all the first-priority secured obligations, including the RBL facility, and the second-priority secured obligations, including the Notes and related Guarantees. In the event of a total or partial loss affecting any of our assets, certain items may not be easily replaced. Accordingly, even though there may be insurance coverage, the extended period needed to obtain replacement units or inventory may cause significant delays, which may have an adverse impact on our operations and results. In addition, certain laws and regulations may prevent rebuilding substantially the same facilities in the event of a loss, which may have an adverse impact on our operations and results. Such adverse impacts may not be covered, or fully covered, by property or business interruption insurance.

Indebtedness under the Notes will be subject to the Senior Lien Intercreditor Documents which provide that the RBL facility and certain other future first-priority indebtedness will be senior to the Notes to the extent of the value of the Collateral securing those obligations.

Substantially all the assets owned by the Issuer and the Guarantors on the issue date of the Notes or thereafter acquired, and all proceeds therefrom, will be subject to first-priority liens in favor of the lenders and other secured parties under the RBL facility and certain other future creditors, and obligations under the Notes are secured by a second-priority lien on such Collateral. The second-priority liens on the Collateral securing the Notes and Guarantees are therefore lower in priority than the liens securing the Issuer and/or any Guarantor's obligations under the RBL facility. In addition, under the indenture, the Issuer and the Guarantors may, from time to time, be permitted to incur additional indebtedness, which may be secured by liens on the Collateral that rank senior in priority to the liens securing the Notes and the Guarantees. As such, holders of the indebtedness under our RBL facility and any such other first-priority indebtedness will be entitled to realize proceeds from the realization of value of the Collateral to repay such indebtedness in full before the holders of the Notes and the Guarantees will be entitled to any recovery from such Collateral. As a result, the Notes and the Guarantees are effectively junior in right of payment to indebtedness under the RBL facility, and any such other first-priority indebtedness, to the extent that the realizable value of the Collateral does not exceed the aggregate amount of such indebtedness.

It is possible that the realizable value of the Collateral securing the Notes and the Guarantees may not be sufficient, in an insolvency or similar proceeding, to satisfy the claims of all effectively senior creditors, along with those of the holders of the Notes and the Guarantees and any other creditors of indebtedness ranking pari passu with the holders of the Notes and the Guarantees.

Your right to exercise remedies with respect to the Collateral will be governed by, and materially limited by, the Senior Lien Intercreditor Documents.

The rights of holders of the Notes with respect to the Collateral will be governed by, and materially limited by, the Senior Lien Intercreditor Documents. The Senior Lien Intercreditor Documents provide that, at any time that any obligations that are secured by first-priority liens remain outstanding, any actions that may be taken in respect of the Collateral (including the ability to commence enforcement proceedings against the Collateral and to control the conduct of such proceedings) will be at the direction of the holders of such indebtedness. Under such circumstances, as set out below, the Trustee (or its agent) on behalf of the holders of Notes will not have the ability to control or direct such actions, even if an event of default under the indenture governing the Notes has occurred or if the rights of the holders of Notes are materially and adversely affected. The holders of indebtedness secured by first-priority liens are under no obligation to take into account the interests of the holders of the Notes and the Guarantees when determining whether and how to exercise their rights with respect to the Collateral, subject to the Senior Lien Intercreditor Documents, and their interest and rights may be significantly different from or adverse to yours.

In the event that the Issuer or any Guarantor is declared bankrupt, becomes insolvent or is liquidated or reorganized, their obligations under the RBL facility and other first-priority secured obligations will be entitled to be paid in full from their assets pledged as security for such obligation before any payment from such assets or the proceeds thereof may be made with respect to the Notes. Holders of the Notes would then participate ratably in the remaining assets pledged as Collateral, with all holders of indebtedness that are deemed to rank equally with the Notes based upon the respective amount owed to each creditor. Also, under the Senior Lien Intercreditor Documents, the holders of the Notes may be required to turn over certain funds they may receive in any insolvency or liquidation proceeding to the lenders under the RBL facility and other first-priority secured obligations under certain circumstances.

In addition, if we and/or any Guarantors experience certain defaults under the RBL facility and other first-priority secured obligations, the lenders and other secured parties of such obligations could declare all of the funds borrowed thereunder, together with accrued and unpaid interest, immediately due and payable and foreclose on, or take other enforcement action with respect to, the assets pledged as Collateral. However, if there were an event of default under the Notes, the holders of obligations that are secured by first-priority liens could decide not to proceed against the Collateral securing the Notes, regardless of whether or not there is a default under such obligations that are secured by first-priority liens. In the event such holders do not exercise their right with respect to the Collateral, the only remedy available to the holders of the Notes would be to sue for payment on the Notes, subject to the rights of the Common Security Agents to realize or foreclose on the Collateral under the Senior Lien Intercreditor Documents following acceleration of the Notes.

While any indebtedness secured by first-priority liens remains outstanding, the holders of the Notes and the Guarantees and any other creditors of indebtedness secured on a pari passu basis with the holders of the Notes and the Guarantees will be entitled to exercise certain rights or remedies with respect to the Collateral only after a standstill period of 180 days and provided the holders of such first-priority secured indebtedness have not taken enforcement action with respect to a material portion of the Collateral and no insolvency event has occurred and no insolvency proceeding has been commenced by or against us or any Guarantor, provided that, with respect to the Borrowing Base Priority Collateral while any first-priority lien obligations (other than indebtedness under the RBL facility (including any refinancing of the RBL facility)) is outstanding, the holders of such first priority liens (rather than the holders of the Notes) will have the right to exercise such rights or remedies following such standstill period.

Under the Senior Lien Intercreditor Documents, the authorized representative of the holders of the Notes may not object following the filing of a bankruptcy petition to any debtor-in-possession financing or to the use of the Collateral to secure that financing, if the same has been consented to by the lenders under the RBL facility (or their authorized representative), subject to certain conditions and limited exceptions. See "Description of the Notes – Security Documents." After such a filing, the value of the Collateral could materially deteriorate, and the holders of the Notes would be unable to raise an objection.

Even though the holders of the Notes will benefit from a second-priority lien on the Collateral, if there is more than one series of second-priority indebtedness outstanding, the notes and Guarantees will be subject to the Second Lien Intercreditor Agreement and the representative of the holders of other second-priority indebtedness may control actions with respect to the Collateral.

In addition to the limitations on the rights of the holders of the Notes with respect to the Collateral under the Senior Lien Intercreditor Documents, the rights of the holders of the Notes with respect to the Collateral that will secure the Notes on a second-priority basis will also be subject to the Second Lien Intercreditor Agreement if there is more than one series of second-priority indebtedness. Under the terms of the Second Lien Intercreditor Agreement, the representative of holders of another series of second-priority indebtedness may control actions with respect to the Collateral if such other series of second-priority indebtedness has an aggregate principal amount greater than the aggregate principal amount outstanding of the Notes. The interests of holders of other second-priority indebtedness may differ from the interests of holders of the Notes and there can be no assurance that the representative of any other series of second-priority indebtedness would take actions that align with the interests of holders of the Notes.

Many of the restrictive covenants contained in the indenture will not apply during any period in which the Notes are rated investment grade by two rating agencies and the holders of the Notes will lose the protection of these covenants during any such periods.

Many of the covenants contained in the indenture will not apply to us during any period in which the Notes are rated investment grade by any two of Moody's Investors Service, Inc., Fitch Ratings, Inc. and Standard & Poor's Ratings Services, provided that at such time no default or event of default has occurred and is continuing. Such covenants will include restrictions on, among other things, our ability to make certain distributions or other restricted payments, incur indebtedness and enter into certain other transactions. There can be no assurance that the Notes will ever be rated investment grade or that if the Notes ever are rated investment grade, they will maintain these ratings. However, suspension of these covenants would allow us to engage in certain transactions that would not be permitted while these covenants were in force. For example, during any such suspension of these covenants, we would be able to make dividends and distributions and incur substantial additional debt in amounts that would not otherwise be permitted while these covenants were in force. To the extent the covenants are subsequently reinstated, any such actions taken while the covenants were suspended would not result in an event of default under the indenture. See "Description of the Notes – Certain Covenants."

Changes in our credit ratings could negatively impact the market price or liquidity of the Notes.

Credit rating agencies continually revise their ratings for the companies that they follow, including us. Credit rating agencies also evaluate our industry as a whole and may change their credit ratings for us based on their overall view of our industry. Additionally, we cannot be sure that credit rating agencies will maintain their ratings on the Notes. A negative change in our ratings could have a negative impact on the future trading prices of the Notes and on our ability to secure future debt financing on commercially reasonable terms or at all.

Our credit ratings could be downgraded.

As of the date of this offering memorandum, our corporate credit rating is "B" from S&P Global Ratings, and "B" from Fitch Ratings, Inc.. Credit ratings are subject to revision, suspension or withdrawal at any time by the assigning rating agency. Rating agencies may also revise or replace entirely the methodology applied to derive credit ratings. We can give no assurances that our credit rating will remain for any period of time or that our credit rating will not be lowered or withdrawn entirely by a rating agency if, in its judgment, circumstances in the future so warrant, or if a different methodology is applied to derive that credit rating.

Any downgrade of one or more of our credit ratings could impact our ability to obtain financing, increase our future financing costs, affect the terms on which suppliers extend us credit, impact our ability to access capital markets and/or have an adverse effect on the trading price of the Notes. A downgrade could also cause the instruments governing any future debt to contain more restrictive covenants, which in turn could limit our ability to obtain additional financing or to respond to changes in business, economic or market conditions.

Service of process, enforcement of judgments and bringing of original actions in the United States, Australia, England and Brazil and other jurisdictions where we have or may in the future have assets may be difficult or impossible.

The Parent Guarantor and certain of the Subsidiary Guarantors are corporations incorporated under the laws of Australia. The Issuer and other Subsidiary Guarantors are corporations incorporated under the laws of Brazil and the U.S. In addition, a majority of our directors, executive officers and managers of each of the Issuer and the Guarantors and certain of the other parties named in this offering memorandum reside outside the United States. A substantial portion of our assets and the assets of these other persons are located outside the United States. As a result, it may be difficult or impossible for you to effect service of process for a lawsuit within the United States upon such persons, including with respect to matters arising under the U.S. Securities Act, or to enforce against any of them judgments in non-U.S. courts obtained in a court of the United States predicated upon, among other things, the civil liability provisions of the U.S. securities laws of the United States or state securities laws. There is doubt as to the enforceability, in original actions in Australian courts, of liabilities predicated solely on the U.S. federal securities laws and as to the enforceability, in Australia. See "Enforcement of civil liabilities."

The Senior Lien Intercreditor Documents, the Second Lien Intercreditor Agreement (if applicable), and certain of the security documents, are governed by the laws of England and Wales. The United States and England and Wales do not have a treaty between them providing for the reciprocal recognition and enforcement of judgments in civil and commercial matters. Consequently, a final judgment for payment rendered by any federal or state court in the United States based on civil liability, whether or not predicated solely upon U.S. federal securities laws, would not automatically be recognized or enforceable in England and Wales. In order to enforce any such U.S. judgment in England and Wales, proceedings must first be initiated before a court of competent jurisdiction in England and Wales. In such an action, an English court would not generally reinvestigate the merits of the original matter decided by the U.S. court (subject to what is said below) and it would usually be possible to obtain summary judgment on such a claim (assuming that there is no good defense to it). Summary judgment is a procedure by which the English court can dispose of all or part of a claim without proceeding to a full trial. Recognition and enforcement of a U.S. judgment by an English court in such an action may be conditional upon (among other things) the following:

- the U.S. court having had jurisdiction over the original proceedings according to English conflicts of laws principles and rules of English private international law (in other words, it does not matter that the U.S. court had jurisdiction according to its own law, but instead whether it had jurisdiction according to the rules of English private international law);

- the U.S. judgment not having been given in breach of a jurisdiction or arbitration clause;

- the U.S. judgment being final and conclusive on the merits in the sense of being final and unalterable in the court which pronounced it and being for a debt for a definite sum of money;

- the U.S. judgment not contravening English public policy or statute in England and Wales;

- the U.S. judgment not being for a sum payable in respect of taxes, or other charges of a like nature, or in respect of a penalty or fine, or otherwise involving the enforcement of a non-English penal or revenue law;

- the recognition and enforcement of the U.S. judgment not being restricted by the provisions of the Protection of Trading Interests Act 1980;

- the U.S. judgment not having been obtained by fraud or in breach of English principles of natural or substantial justice;

- there not having been a prior inconsistent, determinative or conflicting judgment of the courts of England and Wales or another court whose judgment is entitled to recognition in England and Wales;

- the U.S. judgment not having been wholly satisfied or not being enforceable by execution in the U.S.;

- the party seeking enforcement providing security for costs, if ordered to do so by the English court; and

- the English enforcement proceedings being commenced within the relevant limitation period.

Subject to the foregoing, investors may be able to enforce in England and Wales judgments in civil and commercial matters that have been obtained from U.S. federal or state courts. However, we cannot assure you that those judgments will be recognized or enforceable in England and Wales. In addition, it is questionable whether an English court would accept jurisdiction and impose civil liability if proceedings were commenced in England or Wales in an original action predicated solely upon U.S. federal securities laws. Further, it may not be possible to obtain a judgment in England and Wales or to enforce the judgment if the judgment debtor is subject to any insolvency or similar proceedings, of if the judgment debtor has any setoff or counterclaim against the judgment creditor. Finally, in any enforcement proceedings, the judgment debtor may raise any counterclaim that could have been brought if the action had been originally brought in England and Wales unless the subject of the counterclaim was in issue and denied in the U.S. proceedings.

It may be difficult for you to enforce judgments against us or against our directors and executive officers in Brazil.

Pursuant to Brazilian law, judgments of non-Brazilian courts for the payment of money, including for civil liabilities predicated upon the laws of countries other than Brazil, including the U.S. securities laws, subject to certain requirements described below, may be enforced in Brazil. A judgment against either us or any other person described above obtained outside Brazil would be enforceable in Brazil against us or any such person without reconsideration of the merits, upon recognition of that judgment by the Brazilian Superior Court of Justice (*Superior Tribunal de Justiça*). Such recognition, generally, will occur if the foreign judgment: (i) fulfills all formalities required for its enforceability under the laws of the place where it was issued; (ii) is issued by a competent court and/or authority in the jurisdiction where it was awarded, after proper service of process on the parties (if made in Brazil, service of process must be effected in accordance with Brazilian law), or after sufficient evidence of the parties' absence as required by applicable law; (iii) is binding and can be enforced in the jurisdiction in which it was issued; (iv) is effective in the jurisdiction where the decision was issued; (v) is not in conflict with a previous final and binding (res judicata) judgment on the same matter and involving the same parties, cause of action and claim issued in Brazil; (vi) is authenticated by the Brazilian consulate with jurisdiction over the place the judgment is rendered, unless such foreign judgment was authenticated in a country that is signatory of the Hague Convention Abolishing the Requirement of Legalization for Foreign Public Documents dated as of October 5, 1961; (vii) is translated into Portuguese by a certified sworn translator, unless an exemption is provided by an international treaty to which Brazil is a signatory; and (viii) is not contrary to Brazilian national sovereignty or public policy or morality or violate human dignity (as provided in Article 17 of the Law of Introduction to the Brazilian Law in Article 963, VI, of the Brazilian Code of Civil Procedure and in Article 216-F of the Brazilian Superior Court of Justice's Regiment). This recognition process may be time-consuming and may also give rise to difficulties in enforcing the foreign judgment in Brazil. Accordingly, we cannot assure you that the recognition process would be conducted in a timely manner or that a Brazilian court would enforce a monetary judgment for violation of the laws of countries other than Brazil, including the U.S. securities laws. Additionally, (i) civil lawsuits may be brought before Brazilian courts in connection with this offering memorandum based solely on the federal securities laws of the United States and that, subject to applicable law, Brazilian courts may enforce such liabilities in such lawsuits against us (provided that provisions of the federal securities laws of the United States do not contravene Brazilian public policy, good morals or national sovereignty), and provided further that, under Brazilian law, Brazilian courts may assert jurisdiction whenever the defendant is domiciled in Brazil, the obligation has to be performed in Brazil or the subject matter under dispute originates in Brazil, considering that Brazilian courts may exercise jurisdiction over such matters or disputes pursuant to article 88 of the Brazilian Civil Procedure Code; and (ii) the ability of a judgment creditor or the other persons named above to satisfy a judgment by attaching certain assets of tours is limited by provisions of Brazilian bankruptcy, insolvency, liquidation, reorganization or similar laws, given that assets are located in Brazil. However, the application of a foreign body of law by Brazilian courts may be troublesome, as Brazilian courts consistently base their decisions on domestic law or refrain from applying a foreign body of law for a number of reasons. There is a risk that Brazilian courts, considering a relevant case-by-case rationale, may dismiss a petition to apply a foreign body of law and may adopt Brazilian laws to adjudicate the case. In any case, we cannot assure that Brazilian courts will confirm their jurisdiction to rule on such matter, which will depend on the connection of the case to Brazil and, therefore, must be analyzed on a case-by-case basis. A plaintiff (whether Brazilian or non-Brazilian) who resides outside Brazil or is abroad during the course of litigation in Brazil must provide a bond to guarantee the payment of court expenses and defendant's legal fees, if the plaintiff owns no real property in Brazil, that may ensure such payment, except in case of collection claims based on an instrument (which do not include the Notes issued hereunder), that may be enforced in Brazilian courts without the previous review of its merits (*título executivo extrajudicial*) or counterclaims, as established under article 83 of the Brazilian Code of Civil Procedure (Law No. 13,105/2015). The Notes must have a value sufficient to satisfy the payment of court fees and defendant's attorneys' fees, as determined by the Brazilian judge. Furthermore, if proceedings were brought in Brazil seeking to enforce our obligations in respect of the Collateral, we would be required to discharge our obligations only in reais. Under Brazilian exchange controls, an obligation to pay amounts denominated in a currency other than reais, which is payable in Brazil pursuant to a decision of a Brazilian court, will be satisfied in reais at the rate of exchange in effect on the date of payment, as determined by the Central Bank of Brazil. In addition, companies in Brazil may only remit funds out of Brazil and/or convert such funds into hard currency in strict compliance with foreign exchange rules, and there can be no assurance that such companies would have the ability to convert Brazilian real into dollars or euro, nor that such companies would be able to remit such funds out of Brazil.

The Notes will initially be held in book-entry form, and therefore holders must rely on the procedures of the relevant clearing systems to exercise their rights and remedies.

Unless and until certificated notes are issued in exchange for book-entry interests in the Notes, owners of the book-entry interests will not be considered owners or holders of Notes. Instead, DTC, or its nominee, will be the sole holder of the Notes. Payments of principal, interest and other amounts owing on or in respect of the Notes in global form will be made to the paying agent, which will make payments to DTC. Thereafter, such payments will be credited to DTC participants' accounts that hold book-entry interests in the Notes in global form and credited by such participants to indirect participants. Unlike holders of the Notes themselves, owners of book-entry interests will not have the direct right to act upon our solicitations for consents or requests for waivers or other actions from holders of the Notes. Instead, if a holder owns a book-entry interest, such holder will be permitted to act only to the extent such holder has received appropriate proxies to do so from DTC or, if applicable, a participant. We cannot assure holders that the procedures implemented for the granting of such proxies will be sufficient to enable holders to vote on any requested actions on a timely basis.

USE OF PROCEEDS

We estimate that the net proceeds from this offering will be approximately US$393,000,000 after deducting the discounts to the initial purchasers but before deducting the estimated offering expenses payable by us.

We intend to use a portion of the net proceeds of the offering to repay the outstanding amount of US$246.0 million under our RBL facility, which will remain available to be redrawn, and use the remainder of the net proceeds for general corporate purposes, which may include acquisitions.

CAPITALIZATION

The following table sets forth the capitalization of Karoon Energy Limited on:

- a historical consolidated basis as of December 31, 2023; and
- an as adjusted basis to give effect to the receipt of the net proceeds from the Notes offered by this offering memorandum and repayment of a portion of the RBL facility (after deducting the discounts to the initial purchasers but before deducting estimated offering expenses).

After giving effect to the receipt of net proceeds from the Notes offered by this offering memorandum (after deducting the discounts to the initial purchasers but before deducting estimated offering expenses) as described under "Use of proceeds" and below as of December 31, 2023, Karoon Energy Limited would have had US$289.4 million of cash and cash equivalents and US$383.5 million in borrowings.

You should read the following table in conjunction with "Selected consolidated financial data," "Management's discussion and analysis of financial condition and results of operations" and the Karoon Energy financial statements which were audited or reviewed by PricewaterhouseCoopers and included elsewhere in this offering memorandum.

	As of December 31, 2023	
	Actual(1)	**As adjusted**(1)
		(unaudited)
	(US$ million)	
Cash and cash equivalents	**170.4**	**289.4**
Borrowings(1)		
Current borrowings		
Syndicated loan facility – secured	0.1	0.1
Total current borrowings	**0.1**	**0.1**
Non-current borrowings		
Syndicated loan facility – secured	274.0	–
Notes offered hereby	–	400.0
Transaction costs(2)	(9.6)	(16.6)
Total non-current borrowings	**264.4**	**383.4**
Total borrowings	**264.5**	**383.5**
Equity		
Contributed equity	1,210.8	1,210.8
Accumulated losses	(193.3)	(193.3)
Reserves	(103.5)	(103.5)
Total equity	**914.0**	**914.0**
Total capitalization	**1,178.5**	**1,297.5**

Notes:

(1) Borrowings are recognized initially at fair value, net of transaction costs incurred. Subsequent to initial recognition, borrowings are stated at amortized cost. They are not stated at their drawn principal values.

(2) Transaction costs on an as adjusted basis of US$16.6 million includes US$9.6 million of unamortized expenses related to underwriting, legal fees, administrative fees, and any other costs incurred in connection with the RBL facility and an estimated US$7.0 million of discounts to the initial purchasers in connection with the issuance and initial offering of the Notes offered hereby. Transaction costs do not include other estimated expenses of the offering of the Notes, such as legal and accounting expenses.

Since December 31, 2023, we have used cash on hand to repay US$28.1 million of our borrowings under our syndicated loan facilities. Except as disclosed or contemplated in this offering memorandum, there has been no material change in our capitalization since December 31, 2023.

SELECTED CONSOLIDATED FINANCIAL DATA

The income statement and cash flow information for FY21, FY22, FY23, HY23 and TY23 and the balance sheet information as of June 30, 2021, 2022 and 2023 and December 31, 2022 and 2023 have been extracted from our audited consolidated financial statements as of and for the financial years ended June 30, 2022 and 2023 and the transitional financial year ended December 31, 2023 and our unaudited condensed consolidated financial statements for the half-year ended December 31, 2022, in each case included in this offering memorandum, and reflect the consolidated results of operations, cash flows and assets and liabilities of Karoon Energy Limited for such periods.

Our financial statements have been prepared in accordance with the recognition and measurement principles of AAS and IFRS, which differ from US GAAP. You should read the selected consolidated and combined financial data set forth below together with the information in "Financial information presentation," "Risk factors," and "Management's discussion and analysis of financial condition and results of operations" and the Karoon Energy financial statements included elsewhere in this offering memorandum.

Consolidated Statement of Profit or Loss Data

	FY21	FY22	FY23	HY23	TY23
			(US$ million)		
Revenue	170.8	385.1	566.5	299.4	412.9
Cost of sales	(111.4)	(191.7)	(283.2)	(148.3)	(164.5)
Gross profit	**59.4**	**193.4**	**283.3**	**151.1**	**248.4**
Other income	0.3	0.8	5.7	1.1	2.6
Business development and other project costs[(1)]	(17.6)	(3.4)	–	(1.5)	–
Exploration and evaluation expenditure expensed[(1)]	(3.4)	(3.2)	–	(1.7)	–
Finance costs	(14.4)	(22.7)	(25.4)	(11.7)	(15.9)
Net foreign currency gains/(losses)	(17.1)	6.2	(0.8)	0.3	(8.1)
Other expenses[(1)]	(28.5)	(33.8)	(41.4)	(20.8)	(41.4)
Change in fair value of contingent consideration	(6.6)	(227.1)	(5.2)	(0.4)	(3.5)
Profit/(loss) before income tax	**(27.9)**	**(89.8)**	**216.2**	**116.4**	**182.1**
Income tax (expense)/benefit	32.3	25.4	(53.2)	(38.8)	(59.6)
Profit/(loss) for the financial period attributable to equity holders of the Company	**4.4**	**(64.4)**	**163.0**	**77.6**	**122.5**

Note:

(1) Prior to TY23, we reported our business development and other project costs and our exploration and evaluation expenditure expensed as separate items on our income statement. In TY23, we included these costs in our other expenses line item, and we reclassified our other expenses for FY23 so that it is presented on the same basis.

Consolidated Statement of Financial Position Data

	FY21	FY22	FY23	HY23	TY23
			(US$ million)		
Current assets					
Cash and cash equivalents	133.2	157.7	74.8	163.2	170.4
Receivables	34.2	56.4	73.1	79.3	56.4
Inventories	11.0	19.4	8.7	14.8	18.7
Security deposits	0.2	0.3	–	–	–
Other financial assets	–	–	3.0	–	0.2
Other assets	5.3	11.8	7.6	7.3	6.6
Total current assets	**183.8**	**245.6**	**167.2**	**264.6**	**252.3**
Non-current assets					
Deferred tax assets	36.5	123.0	124.7	125.3	95.2
Inventories	6.5	5.8	8.3	4.5	10.8
Oil and gas assets	736.4	733.0	798.7	813.2	1,391.0
Property, plant and equipment	83	13.3	2.7	2.9	3.1
Intangible assets	0.1	–	0.1	–	0.3
Exploration and evaluation assets	40.9	40.9	85.7	41.3	175.3
Security deposits	1.4	1.3	–	2.4	–
Other financial assets	–	–	–	1.4	–
Other assets	–	1.3	3.0	1.2	4.5
Total non-current assets	**830.1**	**918.6**	**1,023.2**	**992.2**	**1,680.2**
Total assets	**1,014.0**	**1,164.2**	**1,190.4**	**1,256.8**	**1,932.5**
Current liabilities					
Trade and other payables	76.2	68.3	57.2	70.2	68.3
Borrowings	–	–	–	–	0.1
Current tax liabilities	8.3	9.6	5.6	44.8	16.8
Other financial liabilities	–	125.4	86.0	96.1	86.0
Lease liabilities	45.4	43.7	47.2	45.2	48.7
Provisions	0.5	0.4	0.2	0.2	0.2
Total current liabilities	**130.3**	**247.4**	**196.2**	**256.5**	**220.1**
Non-current liabilities					
Trade and other payables	4.3	6.8	5.8	5.6	7.2
Borrowings	–	27.1	28.1	27.6	264.4
Other financial liabilities	71.2	222.0	133.0	214.1	136.5
Deferred tax liabilities	1.8	–	–	–	–
Lease liabilities	267.4	245.2	200.4	222.0	175.7
Provisions	158.8	139.5	153.3	151.9	214.6
Total non-current liabilities	**503.4**	**640.6**	**520.6**	**621.2**	**798.4**
Total liabilities	**633.7**	**888.0**	**716.8**	**877.7**	**1,018.5**
Net assets	**380.3**	**276.2**	**473.6**	**379.1**	**914.0**
Equity					
Contributed equity	905.1	907.5	907.5	907.5	1,210.8
Accumulated losses	(414.4)	(478.8)	(315.8)	(401.2)	(193.3)
Reserves	(110.5)	(152.5)	(118.1)	(127.2)	(103.5)
Total equity	**380.3**	**276.2**	**473.6**	**379.1**	**914.0**

Consolidated Statement of Cash Flows Data

	FY21	FY22	FY23	HY23	TY23
			(US$ million)		
Cash flows from operating activities					
Receipts from customers	137.0	362.9	552.9	276.7	443.3
Payments to suppliers and employees	(56.5)	(116.5)	(135.2)	(66.8)	(106.2)
Net refunds for Peruvian VAT	4.2	–	–	–	–
Payments for exploration and evaluation expenditure expensed	(15.2)	(3.5)	(4.0)	(1.3)	(3.3)
Payments for Baúna transition expenditure	(15.9)	–	–	–	–
Payments for legal settlement	–	(9.6)	–	–	–
Payments for cash flow hedges	–	(20.8)	(13.4)	(12.7)	(2.7)
Interest received	0.3	–	4.2	1.4	1.0
Borrowing and other costs of finance paid	(13.2)	(18.9)	(19.8)	(9.3)	(9.2)
Income taxes paid	(10.8)	(39.4)	(78.8)	(20.9)	(19.5)
Net cash flows from operating activities	**29.8**	**154.2**	**305.9**	**167.1**	**303.4**
Cash flows from investing activities					
Purchase of plant and equipment and computer software	(4.7)	(5.1)	(2.5)	(2.3)	(0.9)
Acquisition of oil and gas assets	(150.0)	(43.6)	(84.5)	–	(636.8)
Acquisition of exploration and evaluation assets	–	–	–	–	(83.0)
Interest received on deposit	–	–	–	–	0.1
Payments for oil and gas assets	(16.0)	(59.6)	(222.5)	(137.1)	(4.2)
Borrowing costs paid for qualifying assets	(0.2)	(5.8)	(2.7)	(1.7)	–
Payments for exploration and evaluation expenditure capitalized	(1.9)	–	(43.1)	(0.5)	(3.3)
Payment for security deposits	3.6	(0.3)	(0.9)	(0.8)	–
Proceeds from disposal of non-current assets	0.0	1.4	–	–	–
Net cash flows used in investing activities	**(169.2)**	**(113.0)**	**(356.2)**	**(142.4)**	**(728.1)**
Cash flows from financing activities					
Principal elements of lease payments	(23.4)	(44.6)	(34.1)	(19.7)	(19.2)
Proceeds from issue of ordinary shares	–	2.4	–	–	312.3
Payment of equity raising costs	–	–	–	–	(8.8)
Proceeds from borrowings	–	30.0	–	–	274.0
Repayment of borrowings	–	–	–	–	(29.9)
Debt facility costs	–	(3.3)	(0.1)	–	(8.6)
Net cash flows (used in)/from financing activities	**(23.4)**	**(15.5)**	**(34.2)**	**(19.7)**	**519.8**
Net increase/(decrease) in cash and cash equivalents	(162.8)	25.7	(84.5)	5.0	95.1
Cash and cash equivalents at beginning of the period	296.4	133.3	157.7	157.7	74.8
Effect of exchange rate changes on the balance of cash and cash equivalents held in foreign currencies	(0.4)	(1.3)	1.6	0.5	0.5
Cash and cash equivalents at end of the period	**133.2**	**157.7**	**74.8**	**163.2**	**170.4**

SELECTED UNAUDITED PRO FORMA COMBINED FINANCIAL INFORMATION

On December 21, 2023, Karoon Energy Limited ("Karoon", or the "Company") completed the acquisition of a 30% working interest in the Who Dat and Dome Patrol fields, including the associated infrastructure, an approximately 16% working interest in the Abilene field and varying interests in adjacent exploration acreage certain interests in the US Gulf of Mexico (the "Acquired Assets") from LLOG (the "Acquisition"). The consideration for the Acquisition was funded by a drawdown from the RBL facility, an issuance of ordinary shares, and existing cash reserves.

The following unaudited pro forma combined statement of profit or loss for the year ended December 31, 2023 combines the historical unaudited financial results of Karoon for the year ended December 31, 2023 with the historical unaudited statement of revenues and direct operating expenses of the Acquired Assets for the period from January 1, 2023 to December 20, 2023. In July 2023, Karoon changed its fiscal year end from June 30 to December 31. Karoon's unaudited financial results for the year ended December 31, 2023 have been derived from (i) its audited consolidated statement of profit or loss and comprehensive income for the year ended June 30, 2023; (ii) its unaudited condensed consolidated statement of profit or loss and comprehensive income for the six months ended December 31, 2022 and (iii) its audited consolidated statement of profit or loss and comprehensive income for the six months ended December 31, 2023. The unaudited statement of revenues and direct operating expenses of the Acquired Assets for the period from January 1, 2023 to December 20, 2023 have been derived from (i) its audited statement of revenues and direct operating expenses of the Acquired Assets for the year ended December 31, 2023 less (ii) the revenue and direct operating expenses of the Acquired Assets for the period from December 21, 2023 to December 31, 2023 derived from the accounting books and records of Karoon.

The unaudited pro forma combined statement of profit or loss is presented on a pro forma combined basis and gives effect to the Acquisition and the related financing, including A$480 million from the issuance of ordinary shares and a US$274 million drawdown from the RBL facility, as if they occurred on January 1, 2023.

Karoon's historical consolidated financial statements have been prepared in accordance with AAS and also comply with IFRS, as issued by the IASB. The Acquired Assets' historical financial information is based on the statements of revenues and direct operating expenses, which have been prepared in accordance with accounting principles generally accepted in the United States of America ("US GAAP") and, for the purposes of the unaudited pro forma combined financial information, have been converted to IFRS on a basis consistent with the accounting policies and presentation adopted by Karoon. Note 1 to the statements of revenues and direct operating expenses included elsewhere in this offering memorandum provides further information regarding the basis of preparation of the statements of revenues and direct operating expenses. The financial statements only represent the net collective working and revenue interests acquired by Karoon, and do not purport to reflect the financial condition or results of operations of the Acquired Assets had such business operated on a stand-alone basis during the periods presented.

The unaudited pro forma combined statement of profit or loss does not include all the information and disclosures required by IFRS for a complete set of financial statements. The unaudited pro forma combined financial information has been derived from and should be read in conjunction with Karoon's consolidated financial statements and the Acquired Assets' statements of revenues and direct operating expenses and related notes, as applicable, and the sections titled "Unaudited pro forma combined financial information," "Risk factors" and "Management's discussion and analysis of financial condition and results of operations" included elsewhere in this offering memorandum.

The pro forma adjustments are transaction accounting adjustments ("Transaction Accounting Adjustments"), which give effect to the Acquisition and drawdown from the RBL facility as if they occurred on January 1, 2023. These adjustments include depreciation and amortization expense that would have been incurred had we owned the Acquired Assets since January 1, 2023 and interest expense that would have been incurred had we drawn US$274 million from the RBL facility on January 1, 2023, as well as a corresponding income tax recovery that would have resulted from these additional expenses. Estimated adjustments have been made to reflect the acquisition method of accounting as required by AAS. We have elected not to present autonomous entity adjustments or management's adjustments and only present the Transaction Accounting Adjustments in the unaudited pro forma combined statement of profit or loss. The Transaction Accounting Adjustments reflected in the unaudited pro forma combined financial information are based on information currently available, assumptions, and estimates underlying the pro forma adjustments and are described in the accompanying notes. Actual results may differ materially from the assumptions used to present the accompanying unaudited pro forma combined financial information. See "Risk factors."

Management believes that the assumptions used to prepare the pro forma combined financial information provide a reasonable basis for presenting the effects of such adjustments and the pro forma combined financial information give appropriate effect to those assumptions and are properly applied in the unaudited pro forma combined financial information. The unaudited pro forma combined financial information is included for informational purposes only and does not purport to reflect the results of operations or financial position that would have occurred had the Acquisition occurred on the assumed acquisition date of January 1, 2023. Accordingly, they should not be relied upon as indicative of our result of operations or financial position had the Acquisition occurred on that assumed acquisition date because, among other reasons, they necessarily exclude various operating expenses and the related income tax effects. Additionally, the unaudited pro forma combined financial information is not a projection of Karoon's results of operations or financial position for any future period to date.

Karoon Energy Limited

Unaudited Pro Forma Combined Statement of Profit or Loss For the year ended December 31, 2023

(in millions of US dollars (US$))

	Karoon for the year ended December 31, 2023 Note 1	Acquired Assets for the period from January 1, 2023 to December 20, 2023 Note 1	Transaction Accounting Adjustments Note 2	Notes	Pro forma combined
Revenue	680.0	147.4	–		827.4
Cost of sales	(299.4)	(27.4)	(76.2)	2(a)	(403.0)
Gross profit	**380.6**	**119.9**	**(76.2)**		**424.3**
Other income	7.2	–	–		7.2
Finance costs	(29.6)	–	(26.0)	2(b)	(55.6)
Net foreign currency gains/(losses)	(9.2)	–	–		(9.2)
Other expenses	(58.8)	–	–		(58.8)
Change in fair value of contingent consideration	(8.3)	–	–		(8.3)
Profit before income tax	**281.9**	**119.9**	**(102.2)**		**299.6**
Income tax expense	(74.0)	–	(4.6)	2(c)	(78.6)
Profit for the financial period attributable to equity holders of the Company	**207.9**	**119.9**	**(106.8)**		**221.0**
Profit per share attributable to equity holders of the Company:					
Basic profit per ordinary share (cents per share)	0.3637			2(d), 3	0.2766
Diluted profit per ordinary share (cents per share)	0.3608			2(d), 3	0.2750

Summary pro forma adjustments, which includes a description of each of the footnotes above, is an integral part of these statements.

Notes to Unaudited Pro Forma Combined Financial Information

1. Basis of presentation

The unaudited pro forma combined financial information has been prepared to illustrate the effect of the Acquisition and has been prepared for informational purposes only.

The unaudited pro forma adjustments are based on information currently available, and assumptions and estimates underlying the unaudited pro forma adjustments are described in the accompanying notes. Actual results may differ materially from the assumptions used to present the accompanying unaudited pro forma combined financial information.

The unaudited pro forma statement of profit or loss for the year ended December 31, 2023 has been prepared using, and should be read in conjunction with, the following:

- Karoon's consolidated statement of profit or loss for the year ended December 31, 2023 which was derived from its audited consolidated statement of profit or loss and comprehensive income for the year ended June 30, 2023 less its unaudited consolidated statement of profit or loss and comprehensive income for the period from July 1, 2022 to December 31, 2022 plus its audited consolidated statement of profit or loss and comprehensive income for the period from July 1, 2023 to December 31, 2023. The audited consolidated financial statements for the period July 1, 2023 to December 31, 2023, audited consolidated financial statements for the year ended June 30, 2023 and the unaudited consolidated financial statements for the period from July 1, 2022 to December 31, 2022, and the related notes are included elsewhere in this offering memorandum; and

- The Acquired Assets' statement of revenues and direct operating expenses for the period from January 1, 2023 to December 20, 2023 which was derived from its audited statement of revenue and direct operating expenses for the year ended December 31, 2023 less the revenue and direct operating expenses of the Acquired Assets for the period from December 21, 2023 to December 31, 2023 which were derived from the accounting books and records of Karoon. The audited statements of revenue and direct operating expenses for the years ended December 31, 2023 and 2022, and the related notes are included elsewhere in this offering memorandum.

The unaudited pro forma combined statement of profit or loss is presented on a pro forma combined basis and gives effect to the Acquisition and the related financing, including A$480 million from the issuance of ordinary shares and a US$274 million drawdown from the RBL facility, as if they occurred on January 1, 2023.

Karoon's historical consolidated financial statements have been prepared in accordance with AAS and also comply with IFRS as issued by the IASB. The historical statement of revenues and direct operating expenses of the Acquired Assets have been prepared in accordance with US GAAP and, for the purposes of the unaudited pro forma combined financial information, have been converted to IFRS on a basis consistent with the accounting policies and presentation adopted by Karoon. There were no adjustments required to convert the Acquired Assets' statement of revenue and direct operating expenses from US GAAP to IFRS.

Karoon's Consolidated Statement of Profit or Loss for the year ended December 31, 2023

	(i) Audited for the year ended June 30, 2023	*Less* (ii) Unaudited for the period from July 1, 2022 to December 31, 2022	*Plus* (ii) Audited for the period July 1, 2023 to December 31, 2023	Unaudited for the year ended December 31, 2023
	(US$ million)			
Revenue	566.5	(299.4)	412.9	680.0
Cost of sales	(283.2)	148.3	(164.5)	(299.4)
Gross profit	**283.3**	**(151.1)**	**248.4**	**380.6**
Other income	5.7	(1.1)	2.6	7.2
Finance costs	(25.4)	11.7	(15.9)	(29.6)
Net foreign currency gains/(losses)	(0.8)	(0.3)	(8.1)	(9.2)
Other expenses	(41.4)	24.0	(41.4)	(58.8)
Change in fair value of contingent consideration	(5.2)	0.4	(3.5)	(8.3)
Profit before income tax	**216.2**	**(116.4)**	**182.1**	**281.9**
Income tax expense	(53.2)	38.8	(59.6)	(74.0)
Profit for the financial period attributable to equity holders of the Company	**163.0**	**(77.6)**	**122.5**	**207.9**

US GAAP to IFRS conversion of the Acquired Assets' Statement of Revenue and Direct Operating Expenses for the period from January 1, 2023 to December 20, 2023

	Historical US GAAP for the year ended December 31, 2023	IFRS Policy	*Less* Historical amounts for the period from December 21, 2023 to December 31, 2023	Historical IFRS for the period from January 1, 2023 to December 20, 2023
	(US$ million)			
Revenues:				
Oil	132.4	–	(4.2)	128.2
Natural gas	16.1	–	(0.5)	15.6
Natural gas liquids	3.6	–	(0.0)	3.6
Total revenues	**152.1**	**–**	**(4.7)**	**147.4**
Direct operating expenses	(30.6)	–	3.2	(27.4)
Revenue less direct operating expenses	**121.4**	**–**	**(1.5)**	**119.9**

The adjustments presented in the unaudited pro forma combined financial information have been identified and presented to provide certain information management considers necessary for an accurate understanding of Karoon after giving effect to the Acquisition. Management has made significant estimates and assumptions in its determination of the pro forma adjustments.

The unaudited pro forma combined financial information is not necessarily indicative of what the actual results of operations would have been had the Acquisition taken place on the dates indicated, nor are they indicative of the future combined results of operations of Karoon after the Acquisition. They should be read in conjunction with the historical financial statements and notes thereto of Karoon and the Acquired Assets. The unaudited pro forma combined financial information does not give effect to any anticipated synergies, operating efficiencies, tax savings, or cost savings that may be associated with the Acquisition. The pro forma adjustments reflecting the consummation of the Acquisition are based on certain currently available information and certain assumptions and methodologies that Karoon believes are reasonable under the circumstances. The assumptions underlying the pro forma adjustments, which are described in the accompanying notes, may be revised as additional information becomes available and is evaluated. Therefore, it is likely that the actual accounting impact of the Acquisition will differ from the pro forma adjustments and it is possible the difference may be material. Karoon believes that these assumptions and methodologies provide a reasonable basis for presenting all of the significant effects of the Acquisition based on information available to management at the time and that the pro forma adjustments give appropriate effect to those assumptions and are properly applied in the unaudited pro forma combined financial information.

2. *Pro Forma Adjustments*

Adjustments included in the unaudited pro forma combined financial information are as follows:

(a) Represents the US$76.2 million increase in depreciation and amortization expense computed on a unit of production basis as if the Acquisition were consummated on January 1, 2023. This depreciation and amortization expense was calculated based on the same accounting policy as explained in Note 12 to the Company's audited financial statements for the period ended December 31, 2023.

(b) Reflects the pro forma increase in interest expense of US$26.0 million. This increase represents the interest on the drawings under Karoon's syndicated loan facility to fund the Acquisition as if they had occurred on January 1, 2023. The US$274 million additional indebtedness carries a variable rate of interest. The rate used to estimate the pro forma interest expense was 9.26% based on the prevailing rates at issuance. An increase of 0.125% in the rate assumed would result in an increase interest expense of US$0.3 million in the unaudited pro forma combined statement of profit or loss. This increase in interest expense in each period would cause a corresponding decrease in net income.

(c) Reflects the tax impact of the profit from the Acquired Assets and the Transaction Adjustments at the statutory tax rate of 26% effective in United States. Applying this rate to the sum of the US$76.2 million depreciation and amortization expense described in (a) above and the US$26.0 million interest expense described in (b) above results in a US$26.6 million tax recovery as part of the Transaction Accounting Adjustments.

(d) Reflects increase in number of ordinary shares outstanding as a result of the equity issued to partially fund the Acquisition.

3. *Earnings per share*

Represents the net earnings per share calculated using the historical weighted average shares outstanding, and the issuance of additional 234,343,405 shares in connection with the Acquisition, assuming the shares were outstanding since January 1, 2023. As the Acquisition is being reflected as if it had occurred at the beginning of the period presented, the calculation of weighted average shares outstanding for basic and diluted net earnings per share assumes that the shares issued in connection with the Acquisition have been outstanding for the entire period presented.

4. *Reconciliation of EBITDA and Underlying EBITDA*

The following table shows our EBITDA, Underlying EBITDA reconciled to Karoon's historical consolidated and pro forma combined profit before income tax for the year ended December 31, 2023.

	Year ended December 31, 2023	
	Historical	Pro Forma
	(US$ million)	
Profit before income tax	**281.9**	**299.6**
Add back: Depreciation and amortization – oil and gas assets (excluding depreciation on our floating production, storage and offloading facility right of use asset)	98.8	175.0
Add back: Depreciation and amortization – non oil and gas assets	1.0	1.0
Less: Finance income	(5.4)	(5.4)
Add back: Finance costs (excluding interest on our floating production, storage and offloading facility right of use asset)	15.3	41.3
EBITDA	**391.6**	**511.5**
Add back: Restructure costs	–	–
Add back: Change in fair value of contingent consideration	8.3	8.3
Add back: Fair value losses on hedges	8.4	8.4
Add back: Social investments	2.3	2.3
Add back: FX gains/(losses)	9.2	9.2
Add back: Pitkin legal settlement	–	–
Add back: Who Dat acquisition transaction costs	10.8	10.8
Add back: Baúna acquisition transaction costs	–	–
Add back: Inventory impaired	–	–
Less: Writeback of inventory	(1.6)	(1.6)
Underlying EBITDA	**429.0**	**548.9**

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

You should read the following discussion and analysis of our financial position and results of operations together with the selected financial information and consolidated financial statements included elsewhere in this offering memorandum. This section contains forward-looking statements that involve risks, uncertainties and assumptions. Our actual results may differ materially from those anticipated in these forward-looking statements as a result of a number of factors, including those set out in "Risk factors."

This discussion and analysis is divided into the following sections:

- **Overview** – description of our business and our operating segments, our key income statement line items and a discussion of the key factors affecting our results of operations;

- **Results of operations** – a discussion and analysis of our consolidated results of operations for the transitional financial year ended December 31, 2023 ("TY23") compared to the half-year ended December 31, 2022 ("HY23"), the financial year ended June 30, 2023 ("FY23") compared to the financial year ended June 30, 2022 ("FY22"), and FY22 compared to the financial year ended June 30, 2021 ("FY21");

- **Liquidity and capital resources** – an analysis of our cash flows and sources and uses of cash;

- **Contractual obligations and off-balance sheet arrangements** – a summary of our debt and contractual obligations and our off-balance sheet arrangements;

- **Quantitative and qualitative disclosures about market risk** – disclosures regarding our market risk; and

- **Critical accounting policies –** a discussion of our accounting policies that require critical judgments and estimates.

Overview

Our business

We are an international offshore upstream oil and gas production and exploration company headquartered in Melbourne, Australia, with assets in Brazil and the United States of America. In Brazil, we own and operate the producing Baúna, Piracaba, and Patola fields, which we refer to as Baúna, and are party to concession agreements, in the Santos Basin. In the United States of America, we own non-operated interests in the producing Who Dat, Dome Patrol, and Abilene oil and gas assets, which we refer to as Who Dat, as well as interests in exploration licences, located in the US Gulf of Mexico. Our assets are diversified geographically with multiple producing wells in the Santos Basin and US Gulf of Mexico, which are prolific, globally recognized hydrocarbon basins providing us with the opportunity to increase our reserves and resources. At December 31, 2023, we had production from six oil fields and 19 producing wells, and eight pre-development and exploration blocks.

We have achieved strong growth over the last three and a half years. Our revenue increased from US$170.8 million in FY21 to US$385.1 million in FY22 and to US$566.5 million in FY23. From HY23 to TY23, our revenue increased from US$299.4 million to US$412.9 million. In FY21, FY22, FY23, HY23 and TY23, we achieved profit/(loss) for the financial period attributable to equity holders of the Company of US$4.4 million, US$(64.4) million, US$163.0 million, US$77.6 million and US$122.5 million, respectively. Over those same periods, we recorded and underlying EBITDA of US$61.1 million, US$205.2 million, US$321.8 million, US$175.9 million and US$283.0 million, respectively.

Segments

We identify our operating segments based on the geographical location of our assets. For TY23, we identified our three operating segments to be Australia, Brazil and the USA. We also identified an additional segment which we refer to as “All other segments” which includes amounts of a corporate nature that are not specifically attributable to an operating segment, and we included in this segment the costs associated with the closure of our Peruvian operations. We also recognize and de-recognize operating segments as we divest and acquire assets in new geographies. In FY21, we recognized Peru as an operating segment but did not recognize it in subsequent periods as we relinquished our exploration interests in Peru on July 1, 2021, and in TY23, we recognized USA as an operating segment following our acquisition of asset interests in the Mississippi Canyon Blocks in the US Gulf of Mexico from LLOG Exploration Offshore L.L.C. and LLOG Omega Holdings, L.L.C. (together, “LLOG”) on December 21, 2023. In FY22, FY23 and HY23, our three operating segments were Australia, Brazil and our all other segment.

In accordance with AASB 8 *Operating Segments*, we identified these operating segments based on the internal reports that are reviewed and used by our executive management team in assessing performance and the allocation of resources.

Because Brazil was our only significant operating segment for FY21, FY22, FY23, HY23 and TY23, we have not provided further detail regarding our operating segments for these periods in this section. See Note 2, Note 25 and Note 26 to our audited consolidated financial statements for TY23, FY23 and FY22, respectively, for more information about our other operating segments. We expect our USA operating segment to be a significant operating segment in future periods.

Change in fiscal year

Our Board of Directors decided in July 2023 to change our financial year end from June 30 to December 31. This change aligns our financial year with relevant oil and gas industry peers and both Brazil’s and the USA’s tax years, which we expect will streamline the preparation of our annual financial statements. This change in our financial year end resulted in a transitional financial year consisting of six months that began on July 1, 2023 and ended on December 31, 2023 for which we have prepared audited consolidated financial statements and which we identify as “TY23” in this offering memorandum.

For comparative purposes, we have presented the audited results for TY23 as compared to the unaudited results for HY23 in this section.

Key income statement line items

Revenue

For TY23 and FY23, revenue from oil sales accounted for 99.9% and 100% of our total revenue, respectively. Revenue from gas sales accounted for the remainder of our total revenue for TY23.

We sell the oil we produce from Baúna to Shell Western Supply and Trading Limited, or SWST, under a marketing and offtake agreement. Pursuant to this agreement, SWST markets this oil to a range of customers. This agreement will expire on the later of (i) the date on which we cancel all commitments under our RBL facility, (ii) three years after the end of the “Pre-Existing Term”, which is the later of December 9, 2025 or the delivery of 28.6 million barrels of oil pursuant to the agreement, and (iii) when a further 20.0 million barrels of oil have been delivered pursuant to the agreement after the end of the Pre-Existing Term. As of March 31, 2024, 21.9 million barrels of oil have been delivered pursuant to this agreement. We sell all of the oil produced at Baúna at a price equal to the published Brent crude oil price at the time of sale, adjusted for a negotiated price differential and freight logistics and associated costs. Following an amendment to our offtake and marketing agreement with SWST during TY23, SWST may require us to undertake our own oil transportation activities. If this occurs, the freight logistics charges that are netted against our revenue will be reduced, though our cost of sales would increase. See “Business – Our production and exploration assets – Brazil – Producing assets – Baúna – Products, sales, and marketing” for more information about this agreement.

Between December 21, 2023 and March 31, 2024, LLOG sold our share of the oil and gas produced from the Who Dat oil and gas fields on our behalf pursuant to a transitional services agreement. This oil was marketed as Mars grade and sold at a price equal to WTI crude oil as adjusted for the published Mars differential. LLOG sold our share of the gas produced from the Who Dat oil and gas fields off the Platt's Florida Zone 3 or Transco Zone 4 index, both of which are typically at a small premium to the Henry Hub natural gas spot price.

Following the expiry of the transitional services agreement on March 31, 2024, we assumed responsibility for transporting and marketing our share of the oil and gas produced from the Who Dat oil and gas fields. We currently sell our share of crude oil to BP Products North America Inc. under a month-to-month evergreen crude oil purchase agreement at a price equal to the forward price for the following month for WTI crude oil, adjusted for the published Mars differential, a monthly negotiated price differential, transportation costs and a quality adjustment reflecting the quality of the Who Dat crude oil compared to other crude oil transported on the Mars pipeline. We currently sell our share of natural gas on a six-month seasonal contract basis to BP Energy Company under a gas purchase contract at a price equal to the Platt's Florida Zone 3 index, adjusted for a negotiated price differential and the cost of transportation and processing. We sell our share of natural gas liquids under a life-of-asset sales agreement to Williams Field Services, a U.S. based natural gas infrastructure provider, at prices linked to the Mont Belvieu index, as adjusted for the cost of transportation and fractionation. These processing and fractionation costs are paid in kind by the assignment of a percentage of the natural gas liquids processed. We expect to finalize further marketing agreements through 2024, which would give us additional options to optimize sales.

We present our revenues net of all fees and expenses charged by our counterparties under our sales and marketing agreements.

We present the revenue we earn from our Brazilian segment on a gross basis and deduct royalties as part of our cost of sales.

We present the revenue we earn from our USA segment on a net of royalties basis. Because royalties can be taken in kind in the United States, our USA segment revenues are our actual sales less any royalties levied, resulting in lower reported sales volumes and revenue than if we reported on the same basis as our Brazilian segment.

Cost of sales

The major components of our cost of sales are:

- our operating costs;
- for our Brazilian assets, royalties and other government take levied on the production from our producing assets by the relevant government authorities; and
- depreciation and amortization of our oil and gas assets, which includes depreciation associated with the right-of-use component of our *Cidade de Itajaí* floating production, storage and offloading facility charter, which we recognize as a right-of-use asset under AASB 16 *Leases*.

We include in our operating costs our logistics costs, costs under the operating and maintenance contract with OOG-TKP, materials and supplies costs, employee expenses, insurance costs and any other expenses that are directly attributable to our production of oil and gas. Our operating costs are largely fixed in that they are not directly affected by the oil and gas volumes we produce. We also report our unit production costs on a U.S. dollar per barrel of oil equivalent basis, which we calculate by dividing our statutory operating costs plus the costs associated with our floating production, storage and offloading facility charter by our reported production volume. See "– Key operational measures and non-IFRS financial measures – Operational measures – Unit production costs" for the calculation of this measure.

We calculate the depreciation and amortization of our oil and gas assets and the right-of-use component of our floating production, storage and offloading facility charter using the units of production method from the commencement date of production. We initially value the right-of-use asset at cost (i.e. the present value of the related lease liability), and subsequently revalue it at cost less any accumulated depreciation, impairment losses and adjustment for remeasurement of the lease liability. Our floating production, storage and offloading facility charter has a fixed term to February 2026 with renewal options available through 2028. As required by AASB 16, we exercise judgment in determining the lease term for a lease contract that contains a renewal option. As of December 31, 2023, we included the renewal periods as part of the lease term for the purposes of valuing our right-of-use asset. See "– Critical accounting policies – Determining the lease term of contracts with renewal options" for more information about how we exercise this judgment.

We also include in cost of sales the gains or losses associated with the change in our oil and gas inventory during the period.

We may incur transportation costs related to ship-to-ship oil cargo transfers undertaken by us in the Port of Santos, Brazil following an amendment to our marketing and offtake agreement with SWST during TY23.

The following table shows a breakdown of our cost of sales, our reported production volumes and our unit production costs for FY21, FY22, FY23, HY23 and TY23.

	FY21	FY22	FY23	HY23	TY23
Cost of sales					
Operating costs (US$ million)	38.4	57.2	62.0	30.3	30.2
Royalties and other government take (US$ million)	19.0	41.5	66.7	30.3	45.0
Depreciation and amortization – oil and gas assets (US$ million)	65.0	99.4	143.0	81.7	94.2
Change in inventories (US$ million)	(11.0)	(6.4)	11.5	6.0	(12.7)
Transportation costs (US$ million)	–	–	–	–	7.8
Total cost of sales (US$ million)	111.4	191.7	283.2	148.3	164.5
Reported production volumes (MMboe)	3.14	4.64	7.04	3.37	5.47
Unit production costs[1] (US$/bbl)	25.11	25.36	15.75	17.25	11.09

Note:

(1) See "– Key operational measures and non-IFRS financial measures – Operational measures – Unit production costs" for more information about this measure and how we calculate it.

Other income

Other income includes a number of sources of income that we earn outside of oil and gas sales. These include interest income on our financial assets, such as cash and cash equivalents, receivables and security deposits, sundry income and non-cash items such as the write-back of impaired inventory in FY23.

Business development and other project costs

Business development and other project costs consists primarily of the costs and expenses related to our mergers and acquisitions activity. In FY21, these costs also included US$15.7 million of expenses we incurred in transitioning to become an oil operator in connection with our acquisition of Baúna. From and including TY23, we classify our business development and other project costs as part of our other expenses.

Exploration and evaluation expenditure expensed

Exploration and evaluation expenditure expensed reflect the costs we incur and expense in searching for hydrocarbon resources and evaluating the technical feasibility and commercial viability of extracting the resources we identify. We account for exploration and evaluation expenditure expensed using the 'successful efforts' method of accounting. We expense all exploration and evaluation expenditure in relation to an area of interest in the period in which we incur them, other than the cost of successful wells, the costs of acquiring interests in new exploration assets, and appraisal costs relating to determining development feasibility, which we capitalize as exploration and evaluation assets. For exploration wells, we initially capitalize the costs associated with drilling the wells on a well-by-well basis pending the evaluation of whether potentially economic reserves of hydrocarbons have been discovered. We will expense these capitalized costs if no recoverable hydrocarbons are identified. See "– Critical accounting policies – Capitalized exploration and evaluation expenditure" for more information about the judgments we make in capitalizing exploration and evaluation assets.

From and including TY23, we classify exploration and evaluation expenditure expensed as part of our other expenses.

Finance costs

Our finance costs predominantly relate to finance charges on our lease liabilities and the unwinding of the discount that has been applied when calculating the net present value of our restoration provisions. Our finance costs also include interest expenses and other finance charges related to our RBL facility.

Finance charges on lease liabilities

Most of our finance charges on lease liabilities relate to our floating production, storage and offloading facility charter at Baúna.

We initially value a lease liability on its commencement date at the present value of the lease payments we expect to pay over the lease term, discounted using the interest rate implicit in the lease or, if the rate cannot be readily determined, our estimated incremental borrowing rate. We subsequently increase our lease liability by the interest cost, which we recognize as a finance charge on our income statement, and decrease it by any lease payments made. We will also remeasure the lease liability if our estimated future lease payments change as a result of index or rate changes, residual value guarantees or a change in the likelihood of exercise of purchase, extension or termination options. Our floating production, storage and offloading facility charter has a fixed term to February 2026 with renewal options available through 2028. As required by AASB 16, we exercise judgment in determining the lease term for a lease contract that contains a renewal option. As of December 31, 2023, we included the renewal periods as part of the lease term for the purposes of valuing our lease liability. See "– Critical accounting policies – Determining the lease term of contracts with renewal options" for more information about this judgment.

Discount unwinding

We recognize a provision for our restoration obligations on our balance sheet. We calculate this provision by discounting to present value our estimated future restoration obligations, which include the estimated costs of decommissioning and removing an asset and restoring the site. We unwind this discount monthly as we approach the relevant asset's end-of-life, and we recognize the effect of this unwinding as an accretion charge within our finance costs. See "– Critical accounting policies – Provision for restoration" for more information about how we calculate our restoration provisions.

Interest expense

Prior to March 2023, we capitalized the majority of our interest payments under our then-existing debt facilities as a development asset and recognized the remainder as an interest expense. Following the completion of the Patola development in March 2023, we reclassified this development as a production asset from April 2023. Following this reclassification, we now expense all interest payments under our borrowings (including under our RBL facility).

Other finance costs

We include in our other finance costs any commitment fees we pay under our debt facilities and the amortization of capitalized financing costs. Consistent with the treatment of interest expense described above, we now fully expense our financing costs from April 2023.

We also include in other finance costs the write-off of any unamortized transaction costs related to loan facilities that are prepaid and canceled ahead of their stated maturity.

The following table shows a breakdown of our finance costs for FY21, FY22, FY23, HY23 and TY23.

	FY21	**FY22**	**FY23**	**HY23**	**TY23**
			(US$ million)		
Finance costs					
Finance charges on lease liabilities	12.5	16.9	15.5	8.0	6.8
Discount unwinding on net present value of provision for restoration	0.9	2.4	5.0	2.1	3.2
Interest expense	1.0	2.1	2.1	0.4	2.5
Other finance costs	–	1.3	2.8	1.2	3.4
Total finance costs	14.4	22.7	25.4	11.7	15.9

Net foreign currency gains/(losses)

Our functional and financial statement presentation currency is the U.S. dollar, and the majority of our revenues and expenses are denominated in U.S. dollars. However, our administrative and business development expenditures are incurred in Australian dollars, while a portion of our operating and capital expenditures related to our Baúna production assets are incurred in Brazilian real. We translate these transactions into the U.S. dollar using the foreign exchange rates prevailing at the dates of the transactions, and we recognize foreign currency gains and losses from the settlement of these transactions in our income statement. We also translate monetary assets and liabilities denominated in foreign currencies using the financial period end exchange rates and recognize any associated gain or loss in our income statement.

Other expenses

The major components of our other expenses are:

- corporate expenses;
- realized gains/losses on cash flow hedges;
- legal and commercial settlements; and
- share-based payments expense.

Our corporate expenses include net employee expenses, consulting expenses, insurance costs, travel costs, director fees and other expenses.

As of December 31, 2023, we recognized our Brent crude oil price hedges as a cash flow hedging instrument. Our realized gains/losses on cash flow hedges represent the amount that we are in/out of the money on the oil hedges that expire during the period and the amortization of our hedge premiums. Our hedges are in/out of the money when the Brent crude oil price is below/above the bought put option strike price or above/below the sold call option strike price, respectively.

When we designate a derivative as a cash flow hedging instrument, we immediately recognize the ineffective portion of the change in fair value of the derivative in our income statement. The ineffective portion is the amount that we do not expect to offset the change in cash flows of the hedged item or transaction. We recognized no losses for hedge ineffectiveness during TY23 and FY23.

Our share-based payments expense reflects the fair value of the performance rights granted to our executive directors and employees and the change in fair value of our cash-settled share-based payments.

Our other expenses also include expenditure on social investments/sponsorships, which are payments in lieu of corporate income tax which is allowable under Brazilian tax law. There is no effect on our profit/(loss) because of these payments as these amounts replace tax payable.

From and including TY23, we include our business development and other project costs and our exploration and evaluation expenditure expensed within other expenses. We classified these expenses separately in prior periods.

We also reported as part of our other expenses our advisory and transaction costs in relation to the acquisition of interests in the Who Dat assets from LLOG.

The following table shows a breakdown of our other expenses for FY21, FY22, FY23, HY23 and TY23.

	FY21	FY22	FY23	HY23	TY23
			(US$ million)		
Other expenses					
Advisory and transaction costs	–	–	–	–	10.8
Business development and other project costs[(1)]	–	–	3.7	–	0.7
Exploration and evaluation expenditure expensed[(1)]	–	–	3.9	–	3.3
Corporate	12.3	15.4	20.7	9.2	14.0
Realized losses on cash flow hedges	–	11.8	7.1	7.2	8.5
Legal settlement	9.6	–	–	–	–
Depreciation and amortization – non-oil and gas assets	0.7	0.7	0.9	0.4	0.5
Share-based payments expense	4.9	5.7	3.1	2.1	1.4
Social investments/sponsorships	–	–	1.9	1.8	2.2
Loss on disposal of non-current assets	–	–	0.1	0.1	–
Write-down of inventory to net realizable value	0.6	–	–	–	–
Other expenses	0.5	0.2	–	–	–
Total other expenses	28.5	33.8	41.4	20.8	41.4

Note:

(1) Prior to TY23, we reported our business development and other project costs and our exploration and evaluation expenditure expensed as separate items on our income statement. In TY23, we included these costs in our other expenses line item, and we reclassified our other expenses for FY23 so that it is presented on the same basis. In FY21, FY22 and HY23, our business development and other project costs were US$17.6 million, US$3.4 million and US$1.5 million, respectively, and our exploration and evaluation expenditure expensed were US$3.4 million, US$3.2 million and US$1.7 million, respectively.

Change in fair value of contingent consideration

We recognize the change in the fair value of our contingent consideration arrangement in our income statement.

We agreed to pay Petrobras contingent consideration of up to US$285 million plus interest of 2% per annum accruing from January 1, 2019 as part of our acquisition of Baúna. We account for the fair value of this consideration by calculating the present value of the future expected cash outflows. Our estimates are based on our internal assessment of future oil prices, which considers industry consensus and observable oil price forecasts. We re-assess the fair value of this arrangement semi-annually and will record any increase or decrease in fair value as an expense or revenue, respectively, in our income statement. See "– Key factors affecting our results – Fair value adjustments for contingent consideration" for more information about how we calculate the fair value of this contingent consideration arrangement.

Income tax (expense)/benefit

Income tax (expense)/benefit represents the amount of income tax payable or receivable in relation to our profit or loss before tax for the year and any deferred tax. See "– Critical accounting policies – Income tax" for more information about how we calculate deferred tax assets and liabilities. We conduct a foreign exchange translation adjustment monthly on our deferred tax balances using the foreign exchange rates prevailing at the period end date and recognize any movements on our deferred tax balances in our income statement. Most of our income tax expense is recognized in relation to our operations in Australia and Brazil, where the corporate income tax rate is 30% and 34%, respectively. In the USA, we are subject to the federal corporate income tax rate of 24%. Under our current sales agreements, the point of sale for our production is offshore, which means that the resulting revenue is not subject to state taxes. If we sell our products onshore, we may be subject to income taxes in the state or states in which they are sold. We also recognize income tax in the other jurisdictions in which we operate.

Key operational measures and non-IFRS financial measures

We use a number of operational measures and non-IFRS financial measures to assess the financial and operational performance of our business. We believe these operational measures and non-IFRS measures provide useful information about our business and our management considers these measures in analyzing our operating and financial performance. The measures set forth below should be considered in addition to, not as a substitute for or in isolation from, our financial results prepared in accordance with AAS which also comply with IFRS.

Operational measures

Unit production costs

Unit production costs is a measure of the costs directly attributable to our revenue-generating operations on a per barrel of oil equivalent produced basis. We calculate our unit production costs by dividing our statutory operating costs plus the costs associated with our floating production, storage and offloading facility charter by our reported production volumes. The numerator used in this calculation is different from how we calculate our statutory cost of sales, which includes the depreciation and amortization and lease interest related to our floating production, storage and offloading facility right-of-use asset and related lease liability (both of which are capitalized in accordance with AASB 16 *Leases*), respectively. The following tables show how we calculate our unit production costs for FY21, FY22, FY23, HY23, TY23 and for the year ended December 31, 2023 ("CY23"). We also show our *pro forma* unit production costs for CY23 as if we had acquired our share in the Who Dat assets on January 1, 2023.

	FY21			
Unit production costs	**Reported**	**Back out AASB 16**	**Cost of production-related leases**	**Unit production costs**
Operating costs (US$ million)	38.4	–	–	38.4
Capitalized lease(s) depreciation & amortization (US$ million)	28.1	(28.1)	–	–
Capitalized lease(s) interest (US$ million)	12.4	(12.4)	–	–
Cost of lease(s) (US$ million)	–	–	40.5	40.5
Total costs (US$ million)	78.9	(40.5)	40.5	78.9
Reported production volumes (MMboe)	3.14	3.14	3.14	3.14
Unit production costs/boe	25.11	(12.89)	12.89	25.11

Unit production costs	FY22 Reported	Back out AASB 16	Cost of production-related leases	Unit production costs
Operating costs (US$ million)	57.2	–	–	57.2
Capitalized lease(s) depreciation & amortization (US$ million)	44.4	(44.4)	–	–
Capitalized lease(s) interest (US$ million)	16.8	(16.8)	–	–
Cost of lease(s) (US$ million)	–	–	60.4	60.4
Total costs (US$ million)	118.3	(61.2)	60.4	117.6
Reported production volumes (MMboe)	4.64	4.64	4.64	4.64
Unit production costs/boe	25.51	(13.19)	13.03	25.36

Unit production costs	FY23 Reported	Back out AASB 16	Cost of production-related leases	Unit production costs
Operating costs (US$ million)	62.0	–	–	62.0
Capitalized lease(s) depreciation & amortization (US$ million)	57.5	(57.5)	–	–
Capitalized lease(s) interest (US$ million)	15.3	(15.3)	–	–
Cost of lease(s) (US$ million)	–	–	48.8	48.8
Total costs (US$ million)	134.9	(72.9)	48.8	110.8
Reported production volumes (MMboe)	7.04	7.04	7.04	7.04
Unit production costs/boe	19.17	(10.36)	6.94	15.75

Unit production costs	HY23 Reported	Back out AASB 16	Cost of production-related leases	Unit production costs
Operating costs (US$ million)	30.3	–	–	30.3
Capitalized lease(s) depreciation & amortization (US$ million)	34.2	(34.2)	–	–
Capitalized lease(s) interest (US$ million)	8.0	(8.0)	–	–
Cost of lease(s) (US$ million)	–	–	27.8	27.8
Total costs (US$ million)	72.5	(42.2)	27.8	58.2
Reported production volumes (MMboe)	3.37	3.37	3.37	3.37
Unit production costs/boe	21.50	(12.51)	8.25	17.25

Unit production costs	TY23 Reported	Back out AASB 16	Cost of production-related leases	Unit production costs
Operating costs (US$ million)	30.2	–	–	30.2
Capitalized lease(s) depreciation & amortization (US$ million)	33.4	(33.4)	–	–
Capitalized lease(s) interest (US$ million)	6.8	(6.8)	–	–
Cost of lease(s) (US$ million)	–	–	30.4	30.4
Total costs (US$ million)	70.5	(40.2)	30.4	60.6
Reported production volumes (MMboe)	5.47	5.47	5.47	5.47
Unit production costs/boe	12.89	(7.36)	5.56	11.09

Unit production costs	CY23 Historical Reported	Back out AASB 16	Cost of production-related leases	Unit production costs	Pro Forma Remove 11 days Who Dat contribution	Add 12 months abbreviated financials	Unit production costs
Operating costs (US$ million)	61.9	–	–	61.9	(0.64)	21.9	83.16
Capitalized lease(s) depreciation & amortization (US$ million)	56.7	(56.7)	–	–	–	–	–
Capitalized lease(s) interest (US$ million)	14.1	(14.1)	–	–	–	–	–
Cost of lease(s) (US$ million)	–	–	51.4	51.4	–	–	51.4
Total costs (US$ million)	132.7	(70.8)	51.4	113.3	(0.64)	21.9	134.56
Reported production volumes (MMboe)	9.14	9.14	9.14	9.14	(0.09)	2.78	11.8
Unit production costs/boe	14.52	(7.75)	5.62	12.40	(7.09)	7.88	11.38

Weighted average realized sale price

We calculate our weighted average realized oil and gas price (net of selling expenses) for each period by dividing our reported revenue for that period by the amount of barrels of oil equivalent sold in that period.

Our reported sales volumes and production volumes may differ in a given period as we may not sell all of the volumes produced, primarily due to the timing of our oil cargoes, and we may sell volumes produced in the prior period.

The following table summarizes our historical reported sales volumes and revenue for FY21, FY22, FY23, HY23 and TY23.

	FY21	FY22	FY23	HY23	TY23[(1)]
Reported revenue (US$ million)	170.8	385.1	566.5	299.4	412.9
Reported sales volumes (MMboe)	2.90	4.54	7.06	3.41	5.07
Weighted average realized oil and gas price (net of selling expense) (US$/boe)	59.00	84.74	80.20	87.86	81.51

Note:

(1) Includes our share in the Who Dat assets on a NRI basis for the period from December 21, 2023 to December 31, 2023, following the completion of our acquisition.

Non-IFRS financial measures

EBITDA and underlying EBITDA

We define EBITDA as our earnings before interest, tax, depreciation, depletion and amortization (but including the depreciation and interest on our floating production, storage and offloading facility right of use asset). We present underlying EBITDA as our EBITDA as adjusted for several non-cash items and other expenses that we believe are not representative of our underlying performance. Consistent with market practice, we include the depreciation and interest on our floating production, storage and offloading facility right of use asset when calculating our EBITDA. The following table presents a reconciliation of EBITDA and underlying EBITDA for FY21, FY22, FY23, HY23 and TY23.

	FY21	FY22	FY23	HY23	TY23
			(US$ million)		
Profit before income tax	**(27.9)**	**(89.8)**	**216.2**	**116.4**	**182.1**
Add back: Depreciation and amortization – oil and gas assets (excluding depreciation on our floating production, storage and offloading facility right of use asset)	36.8	55.0	85.5	47.5	60.8
Add back: Depreciation and amortization – non oil and gas assets	0.7	0.7	0.9	0.4	0.5
Less: Finance income	(0.3)	(0.2)	(4.0)	(1.1)	(2.5)
Add back: Finance costs (excluding interest on our floating production, storage and offloading facility right of use asset)	2.1	5.9	9.9	3.7	9.1
EBITDA	**11.4**	**(28.4)**	**308.5**	**166.9**	**249.9**
Add back: Restructure costs	–	0.9	–	–	–
Add back: Change in fair value of contingent consideration	6.6	227.1	5.2	0.4	3.5
Add back: Fair value losses on hedges	–	11.8	7.1	7.2	8.5
Add back: Social investments	–	–	1.9	1.8	2.2
Add back: FX (gains)/losses	17.1	(6.2)	0.8	(0.3)	8.1
Add back: Pitkin legal settlement(1)	9.6	–	–	–	–
Add back: Who Dat acquisition transaction costs	–	–	–	–	10.8
Add back: Baúna acquisition transaction costs	15.8	–	–	–	–
Add back: Inventory impaired	0.6	–	–	–	–
Less: Writeback of inventory	–	–	(1.6)	–	–
Underlying EBITDA	**61.1**	**205.2**	**321.8**	**175.9**	**283.0**

Note:

(1) This settlement related a dispute regarding an alleged breach of our exploration obligations in connection with Block Z-38, offshore Peru.

EBITDA and underlying EBITDA are non-IFRS financial measures derived from our financial statements and associated accounting books and records. We present these as a supplemental measure of our performance. EBITDA and underlying EBITDA should not be considered as an alternative to profit before tax or any other measure of financial performance calculated and presented in accordance with IFRS. EBITDA and underlying EBITDA are presented because they are key metrics used by our management to assess our financial performance. We present EBITDA and underlying EBITDA as we believe they provide further insight into the performance of our business and our ability to meet our debt service requirements.

EBITDA and underlying EBITDA have limitations as an analytical tool and investors should not consider it in isolation from, or as a substitute for, our results of operations. Some of the limitations of EBITDA and underlying EBITDA are that: (i) they do not reflect our cash expenditures or future requirements for capital expenditure or contractual commitments; (ii) they do not reflect changes in, or cash requirements for, our working capital needs; (iii) they do not reflect the significant interest expense, or the cash requirements necessary to service interest or principal payments in respect of any borrowings; (iv) although depreciation and amortization are non-cash charges, the assets being depreciated and amortized will often have to be replaced in the future, and EBITDA and underlying EBITDA do not reflect that any cash amortized will often have to be replaced in the future, and EBITDA and underlying EBITDA do not reflect any cash requirements for such replacements; (v) other companies in our industry may calculate EBITDA and underlying EBITDA differently from how we calculate them, limiting their usefulness as a comparative measure; and (vi) they do not reflect gains and losses in foreign exchange rates, which may impact earnings.

Net debt/(cash)

We define our net debt/(cash) as our total borrowings (excluding transaction costs) less cash and cash equivalents. The following table sets forth our calculation of net debt/(cash) as of June 30, 2021, 2022 and 2023 and as of December 31, 2022 and 2023.

	As of June 30,			As of December 31,	
	2021	2022	2023	2022	2023
			(US$ million)		
Total borrowings	–	30.0	30.0	30.0	274.1
Cash and cash equivalents	(133.2)	(157.7)	(74.8)	(163.2)	(170.4)
Net debt/(cash)	**(133.2)**	**(127.7)**	**(44.8)**	**(133.2)**	**103.7**

Gearing ratio

We define our gearing ratio as our net debt divided by net debt plus equity. The following table sets forth our calculation of our gearing ratio as of June 30, 2021, 2022 and 2023 and as of December 31, 2022 and 2023. As our net debt was negative as of June 30, 2021, 2022 and 2023 and as of December 31, 2022, we have not presented our gearing ratio for those dates as we do not believe it to be meaningful.

	As of June 30,			As of December 31,	
	2021	2022	2023	2022	2023
Net debt/(cash) (US$ million)	(133.2)	(127.7)	(44.8)	(133.2)	103.7
Equity (US$ million)	380.3	276.2	473.6	379.1	914.0
Gearing ratio	**N/A**	**N/A**	**N/A**	**N/A**	**10.2%**

Net interest expense/(income)

We define our net interest expense/(income) as our interest expense minus our interest income. The following table sets forth our calculation of our net interest expense/(income) for FY21, FY22, FY23 and the last twelve months to December 31, 2023.

	FY21	FY22	FY23	Twelve months to December 31, 2023
		(US$ million)		
Interest expense	1.0	2.1	2.1	4.2
Interest income	(0.3)	(0.2)	(4.0)	(5.4)
Net interest expense/(income)	**0.7**	**1.9**	**(1.9)**	**(1.2)**

Interest cover ratio

We define our interest cover ratio as our underlying EBITDA divided by our net interest expense. The following table sets forth our calculation of our interest cover ratio for FY21, FY22, FY23 and the last twelve months to December 31, 2023. As we had a net interest income in FY23 and the twelve months to December 31, 2023, we have not presented our interest cover ratio for those periods as we do not believe it to be meaningful.

	FY21	FY22	FY23	Twelve months to December 31, 2023
Underlying EBITDA (US$ million)	61.1	205.2	321.8	428.9
Net interest expense (US$ million)	0.7	1.9	(1.9)	(1.2)
Interest cover ratio	**87.29x**	**108.00x**	**N/A**	**N/A**

Leverage ratio

We define our leverage ratio as our net debt divided by our underlying EBITDA. The following table sets forth our calculation of our leverage ratio for FY21, FY22, FY23 and the last twelve months to December 31, 2023. As our net debt was negative as of June 30, 2021, 2022 and 2023, we have not presented our leverage ratio for those dates as we do not believe the metric to be meaningful for FY21, FY22, FY23.

	FY21	FY22	FY23	Twelve months to December 31, 2023
Net debt/(cash) (US$ million)	(133.2)	(127.7)	(44.8)	103.7
Underlying EBITDA (US$ million)	61.1	205.2	321.8	428.9
Leverage ratio	**N/A**	**N/A**	**N/A**	**0.24x**

Key factors affecting our results

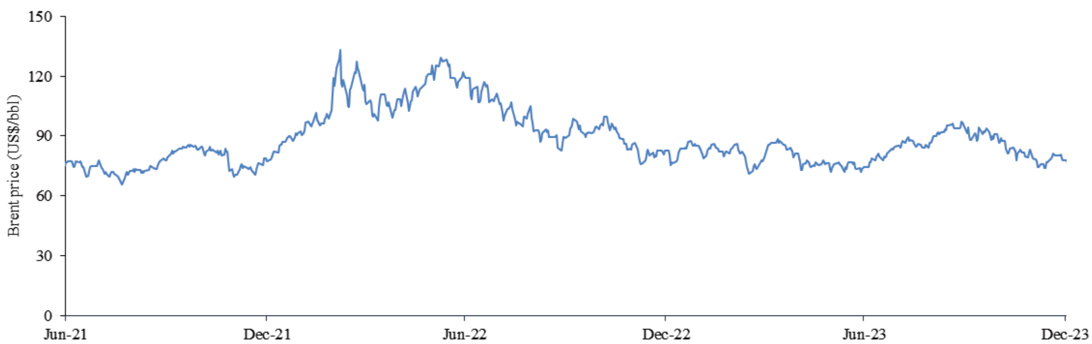
The most significant factors affecting our results of operations are our production volumes and the prices at which we sell our production, which are predominantly set by reference to global oil prices and, to a lesser extent, local gas prices. These factors influence our results of operations both directly, through the amount of revenue we receive and our cost of sales, and indirectly, through the carrying value of our assets and the impact on our hedging book.

Oil and gas prices

Almost all of our revenues are exposed to global oil prices through contract prices that are set by reference to either the Brent crude oil price or the WTI crude oil price. See "– Key income statement line items – Revenue" for more information about the terms under which we sell our oil production. During TY23 and FY23, 100% of our oil sales volumes were sold under terms linked to global oil prices, while 100% of our gas volumes were sold under terms linked to local gas prices during TY23. During TY23, we sold approximately 99% of our oil sales volumes under contracts with pricing set by reference to the Brent crude oil price.

Factors affecting oil prices include worldwide oil supply and demand, the level of economic activity in the markets we serve as well as general worldwide economic conditions, regional political developments and military conflicts in oil producing countries and regions (in particular, Russia/Ukraine), the weather, the ability of the OPEC+ and other producing regions (including North America) to influence global production levels and prices, the price and availability of new technology, the availability and cost of alternative sources of energy and legal and regulatory developments.

Oil and gas prices increased to above pre-pandemic levels in 2021 as a result of increasing COVID-19 vaccination rates and loosening pandemic-related restrictions, triggering an increase in overall demand, and the output limitations implemented by OPEC. In the first half of 2022, the prices for oil and gas increased substantially as a result of underinvestment in new supply, which was exacerbated by Russia's invasion of Ukraine and the international sanctions imposed on Russia as a consequence. In the second half of 2022, the prices for oil declined but remained above pandemic levels, while spot prices for gas remained at near record levels until October 2022 when prices fell due to a warmer than expected Northern hemisphere winter resulting in comfortable storage inventories. In 2023, oil prices decreased to below 2022 averages but still remained elevated when compared to historical levels due to ongoing supply restrictions implemented by OPEC+, the impacts of which were partially offset by economic headwinds. These headwinds included monetary tightening by reserve banks around the world, a high inflationary cost environment, the risk of a U.S. debt default and rising geopolitical tensions in the Middle East. Gas prices also fell significantly when compared to 2022 prices and were slightly depressed when compared to historical levels due to a warm Northern hemisphere winter and the increased uptake of renewable energy sources. In 2024 to date, oil prices decreased to slightly below 2023 averages primarily due to economic headwinds such as the persistently high inflationary cost environment, reduced oil demand, and continuing geopolitical tensions in the Middle East. These headwinds more than offset the ongoing supply restrictions implemented by OPEC+. Gas prices also fell below 2023 prices due to the increased uptake of other energy sources and a warm Northern hemisphere winter. The following chart illustrates the Brent crude oil prices in U.S. dollars per barrel from June 30, 2021 to December 31, 2023.



The following table sets forth our average realized oil price (net of selling expenses) and average realized gas price (net of selling expenses) for FY21, FY22, FY23, HY23 and TY23.

	FY21	FY22	FY23	HY23	TY23
Weighted average realized oil price (net of selling expenses) (US$ per barrel)	59.00	84.74	80.20	87.86	81.96
Weighted average realized gas price (net of selling expenses)[1] (US$ per scf)	N/A	N/A	N/A	N/A	2.2

Note:

(1) We began selling gas on December 21, 2023 after completing the acquisition of the Who Dat assets.

Under our RBL facility, we are required to enter into hedging arrangements to mitigate our exposure to movements in oil prices by reference to a minimum proportion of our forecast production from our borrowing base assets at the relevant time on a rolling two-year basis. The amount we are required to hedge is determined by our collateral coverage ratio at each testing date. We are prohibited from hedging more than 70% of our forecast production over the next two years under our RBL facility. We re-assess our hedging requirements every six months. For more information about our RBL facility, see "Description of other financing arrangements." The table below sets forth our minimum hedging requirements over the following 6, 12, 18 and 24 months as determined by reference to our collateral coverage ratio as of each testing date.

	Minimum hedging requirements on forecast production over the next			
	6 months	12 months	18 months	24 months
Collateral coverage ratio as of each testing date				
Less than or equal to 1.25x	40.0%	30.0%	23.0%	17.0%
Greater than 1.25x and less than or equal to 1.67x	30.0%	23.0%	17.0%	–
Greater than 1.67x and less than or equal to 2.5x	23.0%	17.0%	–	–
Greater than 2.5x and less than or equal to 5.0x	17.0%	–	–	–
Greater than 5.0x	–	–	–	–

As of December 31, 2023, our collateral coverage ratio was 1.0x. See "Description of other financing arrangements – Reserve based lending facility – Covenants and undertakings – Hedging" for a discussion of how we calculate our collateral coverage ratio.

The following table summarizes our hedging arrangements as of December 31, 2023 and June 30, 2023, 2022 and 2021.

As of December 31,	Volume hedged ('000 bbl)	Details of hedges
2023	630 bought put options 423 sold call options	630,000 barrels hedged using bought put options with a strike price of US$65.00 per barrel with an expiry date in 2024. 423,000 barrels hedged using sold call options with a strike price of US$98.00 per barrel with an expiry date in 2024.

As of June 30,	Volume hedged ('000 bbl)	Details of hedges
2023	2,040 bought put options 1,578 sold call options	2,040,000 barrels hedged using bought put options with a strike price of US$65.00 per barrel with an expiry date in 2024. 630,000 barrels hedged using sold call options with a strike price of US$82.50 per barrel with an expiry date in 2024. 947,520 barrels hedged using sold call options with a strike price of US$98.00 per barrel with an expiry date in 2024.
2022	2,946 bought put options 2,946 sold call options	2,316,000 barrels hedged using bought put options with a strike price of US$65.00 per barrel with an expiry date in FY23. 630,000 barrels hedged using bought put options with a strike price of US$65.00 per barrel with an expiry date in 2024. 426,000 barrels hedged using sold call options with a strike price of US$87.50 per barrel with an expiry date in FY23. 1,890,000 barrels hedged using sold call options with a strike price of US$82.50 per barrel with an expiry date in FY23. 630,000 barrels hedged using sold call options with a strike price of US$82.50 per barrel with an expiry date in 2024.

As of June 30,	Volume hedged ('000 bbl)	Details of hedges
2021	3,940 bought put options 3,940 sold call options	994,000 barrels hedged using bought put options with a strike price of US$65.00 per barrel with an expiry date in FY22. 2,316,000 barrels hedged using bought put options with a strike price of US$65.00 per barrel with an expiry date in FY23. 630,000 barrels hedged using bought put options with a strike price of US$65.00 per barrel with an expiry date in 2024. 994,000 barrels hedged using sold call options with a strike price of US$87.50 per barrel with an expiry date in FY22. 426,000 barrels hedged using sold call options with a strike price of US$87.50 per barrel with an expiry date in FY23. 1,890,000 barrels hedged using sold call options with a strike price of US$82.50 per barrel with an expiry date in FY23. 630,000 barrels hedged using sold call options with a strike price of US$82.50 per barrel with an expiry date in 2024.

Since December 31, 2023, we have entered into further hedging arrangements in accordance with our obligations under the RBL facility. The following table summarizes the hedging arrangements we have entered into since December 31, 2023.

Calendar year	Volume hedged ('000 bbl)	Details of hedges
2024	2,695 bought put options 2,695 sold call options	1,300,000 barrels hedged using bought put options with a strike price of US$62.00 per barrel with an expiry date in 2024. 1,395,000 barrels hedged using bought put options with a strike price of US$60.00 per barrel with an expiry date in 2024. 2,695,000 barrels hedged using sold call options with a strike price of US$92.00 per barrel with an expiry date in 2024.
2025	1,569 bought put options 1,569 sold call options	1,569,000 barrels hedged using bought put options with a strike price of US$58.00 per barrel with an expiry date in 2025. 1,569,000 barrels hedged using sold call options with a strike price of US$92.00 per barrel with an expiry date in 2025.

Changes in oil prices can also have an indirect effect on our estimates of oil reserves and the carrying value of our assets. See “Reserves”, “– Oil and gas reserves” and “– Critical accounting policies – Estimates of reserves quantities” for more information.

Movements in oil prices may also impact the fair value of our contingent consideration obligations. For more information, see “– Fair value adjustments for contingent consideration.”

Production volume

From period to period, our production volume is affected by the following main factors:

- natural variability in the production volume of oil and gas fields, which typically ‘ramp up’ to a peak production level shortly after coming online and then decline over time;

- acquisitions and disposals of interests in producing assets;

- production interruptions (including at wellhead, subsea and other gathering infrastructure), which may be planned (for example, for maintenance, refits or upgrades) or unplanned, including plant or equipment failures and natural disasters such as severe hurricanes and earthquakes; and

- well workover programs on existing oil and gas wells to enhance, restore or maintain their productivity.

During TY23 and the three years ended June 30, 2023, the major factors that affected our production were:

- the acquisition of the Baúna oil fields on November 6, 2020 from Petrobras, which produced 3.14 MMbbl during FY21;

- the shutdown of the *Cidade de Itajaí* floating production, storage and offloading facility between March 28, 2023 and May 8, 2023, resulting in no oil production during this period;

- the three well Baúna workover program which completed in late 2022, which added more than 9,200 bopd on average (excluding the shut-down period) throughout the remainder of FY23;

- the Patola development which achieved first oil on March 15, 2023, which added more than 16,500 bopd on average (excluding the shut-down period) throughout the remainder of FY23; and

- operational issues relating to equipment in the gas-lift dehydration unit on the floating production, storage and offloading facility in late 2023 which compromised production at two of our wells at Baúna (SPS-56 and SPS-88), which we estimate reduced our total production in TY23 by approximately 0.3 MMboe.

On December 21, 2023, we acquired interests in the Who Dat assets from LLOG. While these assets only contributed 0.09 MMboe to our production volumes in TY23, we expect these assets to be a major contributor to our production volumes going forward.

Since December 31, 2023, we have remediated the issues relating to equipment on our floating production, storage and offloading facility that impacted production at one of our wells at Baúna (SPS-88). We have been unable to resume normal production at SPS-88 due to what we believe is a mechanical blockage in the well’s gas lift valve. We expect to undertake a workover program in an attempt to return the well to normal production in the fourth quarter of 2024, subject to regulatory approvals and securing appropriate equipment. In conjunction with the operator of the floating production, storage and offloading facility, we are also planning a full shut-down of our operations on the floating production, storage and offloading facility to undertake planned maintenance from mid to late May 2024, and we expect production to resume in early June 2024.

The following tables summarize our historical reported production volumes by asset and by product for FY21, FY22, FY23, HY23 and TY23.

Reported production volume by assets

	For the twelve months ended June 30,			For the six months ended December 31,	
	2021	**2022**	**2023**	**2022**	**2023[1]**
Baúna (MMbbl)	3.14	4.64	7.04	3.37	5.38
Who Dat[1] (MMboe)	–	–	–	–	0.09
Total (MMboe)	3.14	4.64	7.04	3.37	5.47

Note:

(1) Includes our share in the Who Dat assets on a net revenue interest basis for the period from December 21, 2023 to December 31, 2023, following our acquisition.

Reported production volume by product

	For the twelve months ended June 30,			For the six months ended December 31,	
	2021	**2022**	**2023**	**2022**	**2023[1]**
Oil (MMbbl)	3.14	4.64	7.04	3.37	5.44
Gas[1] (MMboe)	–	–	–	–	0.03
Total (MMboe)	3.14	4.64	7.04	3.37	5.47

Note:

(1) Includes our share in the Who Dat assets on a net revenue interest basis for the period from December 21, 2023 to December 31, 2023, following our acquisition.

Royalties and other government take

We are required to pay royalties, special participation fees and research and development levies to the Brazilian government on an ongoing basis.

The Brazilian National Agency for Petroleum, Natural Gas and Biofuels ("ANP") determines the monthly royalty rate to be applied to each concession block. This rate ranges from 5% to 10% of the gross notional revenue (defined as production volume multiplied by the published ANP reference price) from that block, and the ANP will consider the block's geological risks and the expected production, among other factors, in determining the royalty rate.

In October 2022, we were granted a reduction in the royalty rate applied to our incremental production from Baúna pursuant to a Brazilian regulatory regime that incentivizes the ongoing development of mature oil and gas fields. The reduced royalty rate applies to all incremental production from Baúna resulting from the Baúna workover campaign and the Patola field development. For our incremental production up to 50% above the base production profile at Baúna, a royalty rate of 7.5% will apply. For incremental production higher than 50% above the base production profile, a royalty rate of 5% will apply. These reduced royalty rates applied from October 2022.

We are required to pay special participation fees when our quarterly production is in excess of 300,000 m^3 or 1.9 million barrels. We are also required to pay a research & development levy equal to 1% of gross notional revenue in the quarters that we are required to pay special participation fees. The special participation fee is calculated through progressive rates that vary according to the location, lifetime of the field, and production volumes, pursuant to applicable regulations. The special participation fee related to each field is payable on a quarterly basis from the date the high production occurred and is calculated based on the gross notional revenue of each field, less: (i) operational expenses and depreciation in the current quarter; and (ii) any special participation fees and research and development levies paid in the prior period.

In addition, the Brazilian government imposed a temporary crude oil export tax that had effect between March 1, 2023 and June 30, 2023. This scheme levied a 9.2% tax on all of our sales volumes during that period.

For our USA segment, we pay a 12.50% royalty on the value of our share of production from the Who Dat oil and gas fields to the Office of Natural Resources Revenue. In addition, we pay royalties in connection with specific leases to third parties under agreements with prior interest holders. For example, certain limited zones of block MC 502, on which the Who Dat field is partly located, are subject to a 5% overriding royalty stemming from a farm-out agreement with Eni Petroleum US LLC. See "Regulatory overview – Regulatory overview – Brazil – Concession bids – Government participation" and "Regulatory overview – Regulatory overview – Gulf of Mexico – Other oil and gas industry regulations" for more information about the royalty regimes that apply to us.

The following table sets out the royalties and other government take for FY21, FY22, FY23, HY23 and TY23.

	FY21	FY22	FY23	HY23	TY23
			(US$ million)		
Royalties and other government take					
Royalties	19.0	41.5	47.3	27.5	32.0
Special participation tax	–	–	1.4	1.1	8.7
R&D obligations	–	–	3.4	1.7	4.3
Export tax	–	–	14.6	–	–
Total	19.0	41.5	66.7	30.3	45.0

Oil and gas reserves

We rely on our reserves estimates in assessing items such as our asset carrying values, restoration provisions and deferred tax balances. We prepare our reserves estimates in accordance with PRMS 2018 and the ASX listing rules. Our estimates are based on:

- our interpretation of geological and geophysical models;
- reservoir engineering and production engineering analyses and models; and
- assessments of the technical feasibility and commercial viability of producing the reserves.

Our reserves assessments require assumptions to be made regarding future development and production costs, commodity prices, exchange rates and fiscal regimes, all of which are constantly changing. These assumptions in turn influence the economic recoverability of our oil and gas resources and, therefore, what proportion of resources we recognize as reserves. Our reserves estimates may also change as additional geological data is generated through the course of operations. See "Cautionary note regarding reserves and contingent resources" and "Reserves and contingent resources" for more information about our reserves estimates.

Any increase or decrease in our reserves estimates could lead to higher or lower depreciation and/or amortization charges or the immediate write-down of the carrying value of assets (in the event of a decrease in reserves). We immediately recognize the impact of such changes in our income statement for that period. See "Risk factors – Risks relating to our industry and operations – Interim and annual reviews of our reserves and resources may result in reserve and resource write-downs, us recognizing impairments in the carrying value of our assets or changing our development plans" for more information about the potential impact of reserves write-downs.

Exploration and evaluation activities

Our ability to continue as an oil and gas producer is significantly influenced by our ability to identify and develop new oil and gas fields.

We are involved in a number of exploration, appraisal and evaluation activities, including the Neon discovery and geological and geophysical studies at four other exploration tenements in the Santos Basin. The Who Dat joint ventures are involved in exploration and evaluation activities on four exploration tenements in the US Gulf of Mexico. On April 3, 2024, the respective joint venture partners approved the drilling of an appraisal well and an exploration well in Who Dat East and Who Dat South, respectively, and we expect the total cost of the two wells to us to be between US$67 million and US$77 million. We also monitor and evaluate acreage acquisition opportunities potentially available to us through Brazilian regulatory release cycles.

These exploration and evaluation activities may require significant levels of capital in order for us to determine the development feasibility of these tenements. The success or failure of our exploration, appraisal and evaluation activities will affect the level of reserves and resources we recognize and our future development plans for a particular licensed area. Failed exploration and evaluation activities will also increase the exploration expense we recognize in a reporting period. See "– Key income statement line items – Exploration and evaluation expenditure expensed" and "– Critical accounting policies – Capitalized exploration and evaluation expenditure" for more information about how we expense and capitalize exploration expenditure.

The following table sets forth our exploration and evaluation expenses during FY21, FY22, FY23, HY23 and TY23.

	FY21	FY22	FY23	HY23	TY23
			(US$ million)		
Exploration and evaluation expenditure expensed[1].......	3.4	3.2	3.9	1.7	3.3

Note:

(1) Prior to TY23, we reported our exploration and evaluation expenditure expensed as a separate item on our income statement. In TY23, we included these costs in our other expenses line item, and we reclassified our other expenses for FY23 so that it is presented on the same basis.

The following table sets forth our capitalized exploration and evaluation expenses as of December 31, 2023 and 2022 and June 30, 2023, 2022 and 2021. The increase in our capitalized exploration and evaluation expenditure between June 30, 2023 and December 31, 2023 was primarily due to the acquisition of the Who Dat assets.

	As of June 30,			As of December 31,	
	2021	2022	2023	2022	2023
Capitalized exploration and evaluation expenditure........	40.9	40.9	85.7	41.3	175.3

Fair value adjustments for contingent consideration

We agreed to pay Petrobras contingent consideration of up to US$285 million plus interest of 2% per annum accruing from January 1, 2019 as part of our acquisition of Baúna. We account for the fair value of this consideration by calculating the present value of the future expected cash outflows.

The payment of this contingent consideration is dependent on future oil prices each calendar year from 2022 to 2026 inclusive, and we are required to begin making payments when the annual average Platts Dated Brent oil prices threshold is above US$50 a barrel. The contingent consideration payable does not depend on the volume of production from the Baúna assets nor the price at which the oil is actually sold. We test the annual average Platts Dated Brent oil prices annually. After testing, any amounts we deem not payable in that calendar year will be canceled and not carried forward. Any payments that are required to be made are paid in January of the subsequent year. The following table sets out the amount payable each calendar year (in US$ millions and excluding interest) depending on the average Brent crude oil price as described below.

	2022	2023	2024	2025	2026
Average Brent crude oil price (in US$ units)					
Less than US$50	–	–	–	–	–
From and including US$50 to US$55	3	3	3	2	2
From and including US$55 to US$60	17	17	17	8	4
From and including US$60 to US$65	34	34	34	15	6
From and including US$65 to US$70	53	53	53	24	10
Above and including US$70	78	78	78	36	15

Based on our FY22 internal forecasts, which align with our current internal forecasts, we have assumed that the average Brent crude oil prices from 2022 through 2026 will exceed the US$70 per barrel threshold such that we would have to pay the maximum amount of contingent consideration under this arrangement for each calendar year from 2022 through to 2026. This led to us recognizing the present value of the entire contingent consideration arrangement in FY22. Should forecast prices stay above the US$70 per barrel threshold, any other fair market value adjustments we will make to the contingent consideration arrangement will be as a result of a change in the discount rate used to calculate the present value of this arrangement. Should the forecast average Brent crude oil prices drop below the US$70 per barrel threshold at subsequent testing dates for future calendar years, we will revise the fair value of the contingent consideration arrangement accordingly to reflect the new present value of the contingent consideration arrangement.

For FY22, the average Brent crude oil price exceeded US$70, and as a result we paid US$84.5 million to Petrobras in consideration for our acquisition of Baúna in FY23. For FY23, the average Brent crude oil price exceeded US$70, and as a result we paid US$86.0 million to Petrobras in consideration for our acquisition of Baúna in January 2024. Although these payments are reflected in our cash flows for those periods, they are not reflected in our income statement for those periods as fair value adjustments for the present value of those payments was reflected in FY22.

Currency exchange movements

We report our financial results in U.S. dollars, which is the functional currency of our operations in Brazil and the USA.

Our revenue, significant operating expenditure (including the floating production, storage and offloading facility charter) and a large component of capital obligations are predominantly denominated in U.S. dollars. Our foreign exchange risk exposures primarily relate to our corporate overheads and business development expenditures which are incurred in Australian dollars and a portion of our operating and capital expenditures related to our Baúna production assets and the payment of Brazilian taxes which are incurred in Brazilian real. We translate our foreign currency transactions into U.S. dollars using the foreign exchange rates prevailing at the dates of the transactions, and we recognize foreign currency gains and losses from the settlement of these transactions in our income statement. As a result, increases in the value of the Australian dollar and Brazilian real relative to the U.S. dollar increase our costs and reduce our profit and vice versa.

Results of operations

TY23 compared to HY23

Our results for TY23 included 11 days of results from the Who Dat assets. As such, readers should exercise caution in comparing our results for TY23 with HY23.

Consolidated results

We increased production from Baúna materially in TY23 compared to HY23 following completion of the Baúna workover program and Patola field development during FY23. This production increase, while partially offset by decreased oil prices in TY23 compared to HY23, led to our gross profit increasing US$97.3 million, or 64.4%, from US$151.1 million in HY23 to US$248.4 million in TY23. Our EBITDA increased US$83.0 million, or 49.7%, from US$166.9 million to US$249.9 million, and our profit for the financial period attributable to equity holders of the Company increased US$44.9 million, or 57.9%, from US$77.6 million to US$122.5 million.

The following table sets out our consolidated income statement for HY23 and TY23.

	HY23	TY23
	(US$ million)	
Revenue	299.4	412.9
Cost of sales	(148.3)	(164.5)
Gross profit	**151.1**	**248.4**
Other income	1.1	2.6
Business development and other project costs	(1.5)	–
Exploration and evaluation expenditure expensed	(1.7)	–
Finance costs	(11.7)	(15.9)
Net foreign currency gains/(losses)	0.3	(8.1)
Other expenses[1]	(20.8)	(41.4)
Change in fair value of contingent consideration	(0.4)	(3.5)
Profit before income tax	**116.4**	**182.1**
Income tax expense	(38.8)	(59.6)
Profit for financial period attributable to equity holders of the Company	**77.6**	**122.5**

Note:

(1) Includes US$0.7 million of business development and other project costs and US$3.3 million of exploration and evaluation expenditure expensed for TY23.

Revenue

Our reported revenue increased US$113.5 million, or 37.9%, from US$299.4 million for HY23 to US$412.9 million for TY23. This increase was primarily due to our reported oil sales increasing 1.7 MMboe, or 48.4%, from 3.4 MMboe to 5.1 MMboe as a result of the completion of the Baúna workover program in late 2022 and the Patola development in March 2023, partially offset by a number of minor operational issues. The impact of this sales volume increase was partially offset by our weighted average realized oil and gas price (net of selling expenses) decreasing US$6.35 per barrel of oil equivalent, or 7.2%, from US$87.86 per barrel of oil equivalent to US$81.51 per barrel of oil equivalent due to decreases in oil prices. Our Who Dat assets contributed US$3.9 million in reported revenue and 0.1 MMboe in reported sales volumes in TY23.

Cost of sales

Our cost of sales increased US$16.2 million, or 10.9%, from US$148.3 million for HY23 to US$164.5 million for TY23. This increase was primarily due to our royalties and other government take expense increasing US$14.7 million, or 48.5%, from US$30.3 million to US$45.0 million due to our increased oil production and the application of special participation fees, partially offset by the ANP reducing the royalty rate applied to incremental production from Baúna with effect from October 2022. Depreciation and amortization on our oil and gas assets also increased US$12.5 million, or 15.3%, from US$81.7 million to US$94.2 million due to the increase in our oil production, partially offset by the increase in our 2P reserves primarily due to the completion of the Patola development in March 2023. This increase in cost of sales was partially offset by an increase in inventories of US$12.7 million in TY23 as compared to a decrease in inventories of US$6.0 million in HY23. Our operating costs were flat between TY23 and HY23, with an increase in materials and supplies costs and logistics costs as a result of increased production volumes being offset by decreased insurance costs and decreased costs related to our operating and maintenance contract. As a result of the increased production and our largely fixed operating cost base, our unit production costs fell US$6.16 per barrel of oil equivalent, or 35.7%, from US$17.25 per barrel of oil equivalent to US$11.09 per barrel of oil equivalent. The cost of sales associated with our Who Dat assets was US$2.5 million in TY23.

Other income

Our other income increased US$1.5 million, or 136.4%, from US$1.1 million for HY23 to US$2.6 million for TY23. This increase was primarily due to our interest income increasing US$1.4 million, or 127.3%, from US$1.1 million to US$2.5 million primarily due to higher U.S. dollar interest rates and larger cash balances.

Business development and other project costs

Our business development and other project costs decreased US$0.8 million, or 53.3%, from US$1.5 million in HY23 to US$0.7 million in TY23. In TY23, we included our business development and other project costs within other expenses. We classified these expenses separately in our income statement for HY23.

Exploration and evaluation expenditure expensed

Our exploration and evaluation expenditure expensed increased US$1.6 million, or 94.1%, from US$1.7 million in HY23 to US$3.3 million in TY23, primarily due to increased exploration activity at the Neon discovery block. In TY23, we included our exploration and evaluation expenditure expensed within other expenses. We classified these expenses separately in our income statement for HY23.

Finance costs

Our finance costs increased US$4.2 million, or 35.9%, from US$11.7 million in HY23 to US$15.9 million in TY23. This increase was primarily driven by increases in our other finance costs, interest expenses and the discount unwinding on net present value of the provision for restoration. Our other finance costs increased US$2.2 million from US$1.2 million to US$3.4 million primarily due to the payment of a US$1.6 million commitment fee under our RBL facility alongside other transaction costs related to the RBL facility. As a result of us reclassifying the Patola development as a production asset in 2023, we now fully expense the interest expenses under our debt facilities, which was the primary driver behind our interest expense increasing US$2.1 million from US$0.4 million to US$2.5 million. Our discount unwinding on net present value of the provision for restoration increased US$1.1 million, or 52.4%, from US$2.1 million to US$3.2 million due to an increased pre-tax discount rate being applied to our restoration provisions in the prior financial year and the recognition of a restoration provision related to our Patola production asset. This increase in finance costs was partially offset by a decrease in finance charges on lease liabilities of US$1.2 million, or 15.0%, from US$8.0 million to US$6.8 million primarily due to the remeasurement of our lease liabilities following the operational issues at our floating production, storage and offloading facility in late 2023.

Net foreign currency gains/(losses)

We recorded a net foreign currency loss of US$8.1 million for TY23, compared to a net foreign currency gain of US$0.3 million for HY23. This change was primarily due to a US$9.9 million hedging loss we recognized on the settlement of our Australian dollar denominated equity raise in TY23.

Other expenses

Our other expenses increased US$20.6 million, or 99.0%, from US$20.8 million in HY23 to US$41.4 million in TY23. This increase was primarily due to us incurring advisory and transaction costs of US$10.8 million in TY23 in connection with the acquisition of the Who Dat assets compared to US$0 in HY23. An increase in corporate expenses of US$4.8 million, or 52.2%, from US$9.2 million to US$14.0 million, primarily due to increased consulting expenses, employee expenses and IT expenses, also contributed to this increase. In TY23, we included our business development and other project costs and our exploration and evaluation expenditure expensed within other expenses. We classified these expenses separately in our income statement for HY23. These expenses totaled US$4.0 million in TY23. See "– Business development and other project costs" and "– Exploration and evaluation expenditure expensed" above for more information about how these line items impacted our results of operations for TY23 and HY23.

Change in fair value of contingent consideration

Change in the fair value of our contingent consideration obligation for Baúna was a loss of US$3.5 million in TY23 compared to a loss of US$0.4 million in HY23. These losses were due to us increasing the fair value of the contingent consideration arrangement in each period as a result of a change in the discount rate used.

Income tax expense

Our income tax expense increased US$20.8 million, or 53.6%, from US$38.8 million in HY23 to US$59.6 million in TY23. Our current income tax decreased US$26.5 million, or 50.2%, from US$52.8 million to US$26.3 million primarily due to the tax benefits of accelerated depreciation and interest on net equity in TY23. Our deferred income tax expense increased US$47.3 million from a benefit of US$14.0 million to an expense of US$33.3 million, primarily due to a US$48.6 million expense recognized against temporary differences in the deferred tax balance we recognized for the depreciation of our oil and gas assets, partially offset by a US$12.8 million income tax benefit we received for temporary differences in our right-of-use assets.

FY23 compared to FY22

Consolidated results

We increased production from Baúna materially in FY23 following completion of the Baúna workover program and Patola field development. This production increase, while partially offset by decreased oil prices in FY23 compared to FY22, led to our gross profit increasing US$89.9 million, or 46.5%, from US$193.4 million in FY22 to US$283.3 million in FY23. Our financial performance in FY22 was also impacted by a US$227.1 million loss we recognized due to an increase in the fair value of our contingent consideration obligation due to Petrobras for the Baúna acquisition due to increases in expected future oil prices which resulted in the present value of the maximum contingent amount being recognized. As a result, our EBITDA was a loss of US$28.4 million in FY22 compared to a gain of US$308.5 million in FY23, and our profit for the financial period attributable to equity holders of the Company was US$163.0 million in FY23, compared to a loss for the financial period attributable to equity holders of the Company of US$64.4 million in FY22.

The following table sets out our consolidated income statement for FY22 and FY23.

	FY22	FY23
	(US$ million)	
Revenue	385.1	566.5
Cost of sales	(191.7)	(283.2)
Gross profit	**193.4**	**283.3**
Other income	0.8	5.7
Business development and other project costs	(3.4)	–
Exploration and evaluation expenditure expensed	(3.2)	–
Finance costs	(22.7)	(25.4)
Net foreign currency gains/(losses)	6.2	(0.8)
Other expenses[(1)]	(33.8)	(41.4)
Change in fair value of contingent consideration	(227.1)	(5.2)
Profit/(loss) before income tax	**(89.8)**	**216.2**
Income tax (expense)/benefit	25.4	(53.2)
Profit/(loss) for financial period attributable to equity holders of the Company	**(64.4)**	**163.0**

Note:

(1) Includes US$3.7 million of business development and other project costs and US$3.9 million of exploration and evaluation expenditure expensed for FY23.

Revenue

Reported revenue increased US$181.4 million, or 47.1%, from US$385.1 million for FY22 to US$566.5 million for FY23. This revenue increase was primarily due to our oil sales increasing 2.6 MMbbl, or 57.8%, from 4.5 MMbbl to 7.1 MMbbl as a result of the completion of the Baúna workover program in late 2022 and the Patola development in March 2023, partially offset by the 6 week shutdown in production activities after a leak in the gas flare system of the floating production, storage and offloading facility was identified. The impact of this sales volume increase was partially offset by our weighted average realized oil price (net of selling expenses) decreasing US$4.54 per barrel, or 5.4%, from US$84.74 per barrel to US$80.20 per barrel due to decreases in oil prices.

Cost of sales

Cost of sales increased US$91.5 million, or 47.7%, from US$191.7 million for FY22 to US$283.2 million for FY23. This increase in cost of sales was primarily due to depreciation and amortization on our oil and gas assets increasing US$43.6 million, or 43.9%, from US$99.4 million to US$143.0 million due to the increase in our oil production and our larger asset base following the completion of the Baúna workover program and the Patola development. Royalties and other government take expenses also increased US$25.2 million, or 60.7%, from US$41.5 million to US$66.7 million due to our increased oil production, increased special participation fees and the introduction of a temporary crude oil export tax, which led to an export tax of US$14.6 million, partially offset by the ANP reducing the royalty rate applied to incremental production from Baúna with effect from October 2022. As a result of the increased production and our largely fixed operating cost base, our unit production costs fell US$9.61 per barrel, or 37.9%, from US$25.36 per barrel to US$15.75 per barrel.

Other income

Other income increased US$4.9 million, or 612.5%, from US$0.8 million for FY22 to US$5.7 million for FY23. This increase was primarily due to our interest income increasing from US$0.2 million to US$4.0 million primarily due to higher U.S. dollar interest rates.

Business development and other project costs

Business development and other project costs increased US$0.3 million, or 8.8%, from US$3.4 million for FY22 to US$3.7 million for FY23. We included our business development and other project costs within other expenses in FY23 in our audited consolidated financial statements for TY23. We classified these expenses separately in our income statement for FY22.

Exploration and evaluation expenditure expensed

Exploration and evaluation expenditure expensed increased US$0.7 million, or 21.9%, from US$3.2 million for FY22 to US$3.9 million for FY23. This increase was primarily due to increased spend at the Neon discovery block. We included our exploration and evaluation expenditure expensed within other expenses in FY23 in our audited consolidated financial statements for TY23. We classified these expenses separately in our income statement for FY22.

Finance costs

Finance costs increased US$2.7 million, or 11.9%, from US$22.7 million for FY22 to US$25.4 million for FY23. This increase in finance costs was primarily due to our discount unwinding on net present value of provision for restoration increasing US$2.6 million, or 108.3%, from US$2.4 million to US$5.0 million due to an increased pre-tax discount rate being applied to our restoration provisions and the recognition of a restoration provision related to our Patola production asset. An increase in other finance costs of US$1.5 million, or 115.4%, from US$1.3 million to US$2.8 million, primarily due to the payment of a US$1.6 million commitment fee under our RBL facility alongside other transaction costs related to the RBL facility, also contributed to the increase in finance costs. This increase in finance costs was partially offset by a decrease in finance charges on lease liabilities of US$1.4 million, or 8.3%, from US$16.9 million to US$15.5 million due to the remeasurement of our lease liabilities following the shutdown of the floating production, storage and offloading facility.

Net foreign currency gains/(losses)

We recorded a net foreign currency loss of US$0.8 million for FY23, compared to a net foreign currency gain of US$6.2 million for FY22. This change was due to the Brazilian real appreciating in value against the U.S. dollar as compared to the prior period.

Other expenses

Our other expenses increased US$7.6 million, or 22.5%, from US$33.8 million in FY22 to US$41.4 million in FY23. We included our business development and other project costs and our exploration and evaluation expenditure expensed within other expenses in FY23 in our audited consolidated financial statements for TY23. We classified these expenses separately in our income statement for FY22. These expenses totaled US$7.6 million in FY23. See "– Business development and other project costs" and "– Exploration and evaluation expenditure expensed" above for more information about how these line items impacted our results of operations for FY23 and FY22. Excluding the impact of these items on our other expenses, our other expenses would have remained stable between the periods. Our corporate expenses increased US$5.3 million, or 34.4%, from US$15.4 million to US$20.7 million primarily due to increased headcount in Brazil and wage inflation. Meanwhile, our realized losses on cash flow hedges decreased US$4.7 million, or 39.9%, from US$11.8 million to US$7.1 million due to lower oil prices and our share-based payments expense decreased US$2.6 million, or 45.6%, from US$5.7 million to US$3.1 million primarily due to the non-recurrence of share-based payments that were made to outgoing executives in FY22.

Change in fair value of contingent consideration

Change in the fair value of our contingent consideration obligation for Baúna was a loss of US$5.2 million for FY23 compared to a loss of US$227.1 million for FY22. We recognized a change in fair value in FY23 as we made a revision to the discount rate used to calculate the fair value of the contingent consideration arrangement. We recognized the amount in FY22 as we revised our internal Brent crude oil forecast, based on higher oil prices and industry consensus, to be above the US$70 per barrel threshold above which we are required to pay the full amount of the contingent consideration to Petrobras.

Income tax (expense)/benefit

We recognized an income tax expense of US$53.2 million for FY23 compared to an income tax benefit of US$25.4 million for FY22. Our current income tax increased US$34.7 million, or 88.3%, from US$39.3 million to US$74.0 million, primarily due to the profit before income tax we earned during FY23 as compared to the loss before income tax during FY22. A decrease in deferred income tax benefit of US$43.9 million, or 67.9%, from US$64.7 million to US$20.8 million also contributed to our increased income tax expense in FY23. This decrease in deferred income tax benefit was primarily due to the non-recurrence of a tax benefit of US$77.2 million related to our contingent consideration expense during FY22, partially offset by an income tax benefit we received of US$24.6 million due to the appreciation of the Brazilian real against the U.S. dollar during FY23.

FY22 compared to FY21

Our results for FY22 reflect a full financial year of operating the assets acquired from Petrobras, whereas our results for FY21 only reflect such operations from November 7, 2020. As such, readers should exercise caution in comparing our results for the two periods.

Consolidated results

Our gross profit increased US$134.0 million, or 225.6%, from US$59.4 million in FY21 to US$193.4 million in FY22. As noted in "– FY23 compared to FY22 – Consolidated results", our financial performance in FY22 was impacted by a US$227.1 million loss we recognized as a result of the increase in the fair value of our contingent consideration obligation for Baúna. As a result, our EBITDA was US$11.4 million in FY21 compared to a loss of US$28.4 million in FY22. We recorded a loss for the financial period attributable to equity holders of the Company of US$64.4 million in FY22, as compared to a profit for the financial period attributable to equity holders of the Company of US$4.4 million in FY21.

The following table sets out our consolidated income statement for FY21 and FY22.

	FY21	FY22
	(US$ million)	
Revenue	170.8	385.1
Cost of sales	(111.4)	(191.7)
Gross profit	**59.4**	**193.4**
Other income	0.3	0.8
Business development and other project costs	(17.6)	(3.4)
Exploration and evaluation expenditure expensed	(3.4)	(3.2)
Finance costs	(14.4)	(22.7)
Net foreign currency gains/(losses)	(17.1)	6.2
Other expenses	(28.5)	(33.8)
Change in fair value of contingent consideration	(6.6)	(227.1)
Profit/(loss) before income tax	**(27.9)**	**(89.8)**
Income tax benefit	32.3	25.4
Profit/(loss) for financial period attributable to equity holders of the Company	**4.4**	**(64.4)**

Revenue

Reported revenue increased US$214.3 million, or 125.5%, from US$170.8 million for FY21 to US$385.1 million for FY22. This increase was due to our weighted average realized oil price (net of selling expenses) increasing US$25.74 per barrel, or 43.6%, from US$59.00 per barrel to US$84.74 per barrel due to increased oil prices and our reported sales volume increasing 1.6 MMbbl, or 56.5%, from 2.9 MMbbl to 4.5 MMbbl, reflecting our first full year of operating Baúna since acquiring it on November 7, 2020 and high levels of operational uptime.

Cost of sales

Cost of sales increased US$80.3 million, or 72.1%, from US$111.4 million for FY21 to US$191.7 million for FY22. The increase in cost of sales was primarily due to depreciation and amortization on our oil and gas assets increasing US$34.4 million, or 52.9%, from US$65.0 million to US$99.4 million, due to the increase in our oil production. Royalties and other government take expenses also increased US$22.5 million, or 118.4%, from US$19.0 million to US$41.5 million due to our increased oil production. In addition, our operating costs increased US$18.8 million, or 49.0%, from US$38.4 million to US$57.2 million primarily due to us operating Baúna for a full year. Primarily due to us operating Baúna for a full year and associated ramp-up costs, our unit production costs increased US$0.25 per barrel from US$25.11 per barrel to US$25.36 per barrel.

Other income

Other income increased US$0.5 million, or 166.7%, from US$0.3 million for FY21 to US$0.8 million for FY22.

Business development and other project costs

Business development and other project costs decreased US$14.2 million, or 80.6%, from US$17.6 million for FY21 to US$3.4 million for FY22. This decrease was primarily due to non-recurrence of transaction and transition costs we incurred in FY21 in connection with the Baúna acquisition.

Exploration and evaluation expenditure expensed

Exploration and evaluation expenditure expensed decreased US$0.2 million, or 5.9%, from US$3.4 million for FY21 to US$3.2 million for FY22.

Finance costs

Finance costs increased US$8.3 million, or 57.6%, from US$14.4 million for FY21 to US$22.7 million for FY22. This increase in finance costs was primarily due to our finance charges on lease liabilities increasing US$4.4 million, or 35.2%, from US$12.5 million to US$16.9 million due to us leasing the floating production, storage and offloading facility for a full financial year and the increase in interest rates. An increase in the discount unwinding on net present value of provision for restoration of US$1.5 million, or 166.7%, from US$0.9 million to US$2.4 million primarily due to the discount rate applied to these provisions increasing, also contributed to the increase in finance costs.

Net foreign currency gains/(losses)

We recorded a net foreign currency gain of US$6.2 million for FY22 compared to a net foreign currency loss of US$17.1 million for FY21. This change was primarily due to the U.S. dollar appreciating in value against the Australian dollar and Brazilian real.

Other expenses

Other expenses increased US$5.3 million, or 18.4%, from US$28.5 million for FY21 to US$33.8 million for FY22. This increase in other expenses was primarily due to us recognizing realized losses on cash flow hedges of US$11.8 million in FY22 as compared to US$0 in FY21 due to an increase in global oil prices. This increase in other expenses was partially offset by the non-recurrence of a US$9.6 million payment we made in FY21 to settle a dispute regarding an alleged breach of our exploration obligations in connection with Block Z-38, offshore Peru.

Change in fair value of contingent consideration

Change in the fair value of our contingent consideration obligation for Baúna increased US$220.5 million from a loss of US$6.6 million for FY21 to a loss of US$227.1 million for FY22. We recognized a significant increase in the fair value of the contingent consideration obligation to Petrobras in FY22 as we revised our internal Brent crude oil forecast, based on higher oil prices and industry consensus, to be above the US$70 per barrel threshold, above which we are required to pay the full amount of the contingent consideration to Petrobras.

Income tax benefit

Income tax benefit decreased US$6.9 million, or 21.3%, from US$32.3 million for FY21 to US$25.4 million for FY22. Our current income tax increased US$24.0 million, or 156.5%, from US$15.3 million to US$39.3 million, reflecting the increase in our pre-tax profitability excluding the impact of the increase in the fair value of our contingent consideration arrangement. This increase in income tax was partially offset by an increase in deferred income tax benefit of US$17.0 million, or 35.7%, from US$47.7 million to US$64.7 million primarily as a result of a tax benefit of US$77.2 million related to our recognition of a substantial increase in the fair value of our contingent consideration obligation to Petrobras, the effect of which was partly offset by the utilization of Brazilian tax losses and temporary differences arising from foreign exchange movements in the U.S. dollar and Brazilian real exchange rate.

Liquidity and capital resources

Overview

We primarily rely on cash from operations and existing cash on hand in order to fund our operations and capital expenditures. Our ability to fund our business using cash from operations has been and will continue to be influenced by a variety of factors, including those described under "– Key factors affecting our results."

We have historically grown our business by acquiring assets, and we continue to regularly evaluate opportunities to acquire additional assets and companies. See "Business – Our strategy – We intend to grow production volumes through acquisitions, targeting opportunities in North America and Brazil, that leverage our technical expertise and teams in these regions" for more information about our acquisition strategy. We have historically relied on free cash on hand and prudent leverage of the balance sheet through debt facilities as well as equity issuances in order to fund significant acquisitions.

We intend to apply our capital to:

- safe and reliable operating costs;
- sustaining capital expenditure;
- debt servicing; and
- growth investment, balanced with returns to shareholders.

We believe that we have sufficient sources of funds to meet our capital requirements over the next 12 months.

As of December 31, 2023, we had total available liquidity of US$170.4 million, all of which was cash and cash equivalents. As of December 31, 2023, we had outstanding borrowings of US$274.1 million, all of which was first-lien senior secured debt. As of December 31, 2023, we had US$66.0 million undrawn under our RBL facility, all of which was committed but unavailable pending the addition of our interest in the Who Dat assets to the RBL facility borrowing base assets.

For more information about our material financing arrangements, see "Description of other financing arrangements."

Cash flows

Set out below is a summary of our cash flows for the periods indicated.

	FY21	FY22	FY23	HY23	TY23
			(US$ million)		
Cash flows from operating activities					
Receipts from customers	137.0	362.9	552.9	276.7	443.3
Payments to suppliers and employees	(56.5)	(116.5)	(135.2)	(66.8)	(106.2)
Payments for cash flow hedges	–	(20.8)	(13.4)	(12.7)	(2.7)
Borrowing and other costs of finance paid	(13.2)	(18.9)	(19.8)	(9.3)	(9.2)
Income taxes paid	(10.8)	(39.4)	(78.8)	(20.9)	(19.5)
Other operating activities[1]	(26.7)	(13.1)	0.2	0.1	(2.3)
Net cash from operating activities	**29.8**	**154.2**	**305.9**	**167.1**	**303.4**
Cash flows from investing activities					
Acquisition of oil and gas assets	(150.0)	(43.6)	(84.5)	–	(636.8)
Acquisition of exploration and evaluation assets	–	–	–	–	(83.0)
Payments for:					
Oil and gas assets	(16.0)	(59.6)	(222.5)	(137.1)	(4.2)
Exploration and evaluation expenditure capitalized	(1.9)	–	(43.1)	(0.5)	(3.3)
Other investing activities[2]	(1.3)	(9.8)	(6.1)	(4.8)	(0.8)
Net cash used in investing activities	**(169.2)**	**(113.0)**	**(356.2)**	**(142.4)**	**(728.1)**
Cash flows from financing activities					
Principal elements of lease payments	(23.4)	(44.6)	(34.1)	(19.7)	(19.2)
Proceeds from borrowings	–	30.0	–	–	274.0
Proceeds from issue of ordinary shares	–	2.4	–	–	312.3
Other financing activities[3]	–	(3.3)	(0.1)	–	(47.3)
Net cash (used in)/from financing activities	**(23.4)**	**(15.5)**	**(34.2)**	**(19.7)**	**519.8**
Net (decrease)/increase in cash and cash equivalents	(162.8)	25.7	(84.5)	5.0	95.1
Cash and cash equivalents at the beginning of the period	296.4	133.3	157.7	157.7	74.8
Effect of exchange rate changes on the cash and cash equivalents held in foreign currencies	(0.4)	(1.3)	1.6	0.5	0.5
Cash and cash equivalents at the end of the period	**133.2**	**157.7**	**74.8**	**163.2**	**170.4**

Notes:

(1) Includes cash flows from net refunds for Peruvian Vat, payments for exploration and evaluation expenditure expensed, payments for Baúna transition expenditure, payments for legal settlement and interest received.

(2) Includes cash flows from interest received on deposit, purchase of plant and equipment and computer software, borrowing costs paid for qualifying assets, payment for security deposits and proceeds from disposal of non-current assets.

(3) Includes cash flows from payment of equity raising costs, repayment of borrowings and debt facility costs.

Cash flows from operating activities

Net cash inflows from operating activities increased US$136.3 million, or 81.6%, in TY23 from cash inflows of US$167.1 million in HY23 to cash inflows of US$303.4 million for TY23. This increase was primarily due to receipts from customers increasing US$166.6 million, or 60.2%, from US$276.7 million to US$443.3 million, reflecting our higher sales volumes in TY23. This increase was partially offset by payments to suppliers and employees increasing US$39.4 million, or 59.0%, from US$66.8 million to US$106.2 million, primarily due to increased royalties and other government take as a result of our higher production volumes in TY23.

Net cash inflows from operating activities increased US$151.7 million, or 98.4%, in FY23 from cash inflows of US$154.2 million for FY22 to cash inflows of US$305.9 million for FY23. This increase was primarily due to receipts from customers increasing US$190.0 million, or 52.4%, from US$362.9 million to US$552.9 million, reflecting our higher oil sales volumes in FY23. This increase was partially offset by an increase in income taxes paid of US$39.4 million, or 100.0%, from US$39.4 million to US$78.8 million, reflecting the profit we earned during FY23 compared to the loss in FY22.

Net cash inflows from operating activities increased US$124.4 million, or 417.4%, in FY22 from cash inflows of US$29.8 million for FY21 to cash inflows of US$154.2 million for FY22. This increase was primarily due to receipts from customers increasing US$225.9 million, or 164.9%, from US$137.0 million to US$362.9 million, reflecting our higher oil sales volumes as a result of us operating Baúna for a full year and our higher weighted average realized oil price (net of selling expenses) in FY22. This increase was partially offset by an increase in payments to suppliers and employees, including production costs and royalties, of US$60.0 million, or 106.2%, from US$56.5 million to US$116.5 million, reflecting our higher oil sales volumes in FY22. This increase in net cash inflows was also partially offset by an increase in income taxes paid of US$28.6 million, or 264.8%, from US$10.8 million to US$39.4 million, primarily due to our increased profits in Brazil.

Cash flows from investing activities

Net cash outflows from investing activities increased US$585.7 million in TY23 from US$142.4 million for HY23 to US$728.1 million for TY23. This increase was primarily due to our acquisition of the Who Dat assets in TY23, which led to cash outflows of US$636.8 million and US$83.0 million for the acquisition of oil and gas assets and the acquisition of exploration and evaluation assets, respectively. This increase was partially offset by payments for oil and gas assets decreasing US$132.9 million, or 96.9%, from US$137.1 million to US$4.2 million, primarily due to the Baúna workover program and Patola development that we undertook during HY23 and which were completed prior to TY23.

Net cash outflows from investing activities increased US$243.2 million, or 215.2%, in FY23 from US$113.0 million for FY22 to US$356.2 million for FY23. This increase was primarily due to an increase in payments for oil and gas assets of US$162.9 million, or 273.3%, from US$59.6 million to US$222.5 million in connection with capital expenditure for the Baúna workover program, Patola development and ongoing field maintenance. This increase also reflected an increase in cash outflows for the acquisition of oil and gas assets of US$40.9 million, or 93.8%, from US$43.6 million to US$84.5 million, primarily related to the payment of deferred contingent consideration to Petrobras for the Baúna acquisition. Payments for capitalized exploration and evaluation expenditure also increased from US$0 to US$43.1 million primarily due to the two well control drilling campaign on the Neon discovery block we conducted during FY23.

Net cash outflows from investing activities decreased US$56.2 million, or 33.2%, in FY22 from US$169.2 million for FY21 to US$113.0 million for FY22. This decrease in cash outflows was primarily due to a decrease in cash outflows for the acquisition of oil and gas assets of US$106.4 million, or 70.9%, from US$150.0 million to US$43.6 million. The cash outflow for FY21 related to the Baúna acquisition completion payment, whereas the cash outflow for FY22 related to deferred firm consideration paid to Petrobras for the Baúna acquisition. This decrease in cash outflows was partially offset by an increase in payments for oil and gas assets of US$43.6 million, or 272.5%, from US$16.0 million to US$59.6 million primarily due to capital expenditure relating to the Baúna workover program and ongoing field maintenance.

Cash flows from financing activities

We had net cash inflows from financing activities of US$519.8 million in TY23 as compared to net cash outflows from financing activities of US$19.7 million in HY23. The main cash inflows in TY23 were from proceeds from the issue of ordinary shares and proceeds from borrowings of A$480 million and US$274.0 million, respectively, both of which were used to fund our acquisition of asset interests from LLOG. These cash inflows were partially offset by equity raising costs and debt facility costs of US$8.8 million and US$8.6 million, respectively.

Net cash outflows from financing activities increased US$18.7 million, or 120.6%, in FY23 from US$15.5 million for FY22 to US$34.2 million for FY23. This increase was primarily due to the non-recurrence of a debt facility drawdown of US$30.0 million that occurred during FY22. The increase was partially offset by cash outflows for principal elements of lease payments decreasing US$10.5 million, or 23.5%, from US$44.6 million to US$34.1 million primarily due to the temporary shutdown of the floating production, storage and offloading facility.

Net cash outflows from financing activities decreased US$7.9 million, or 33.8%, in FY22 from US$23.4 million for FY21 to US$15.5 million for FY22. This decrease was primarily due to a US$30.0 million debt facility drawdown during FY22. The decrease in net cash outflows was partially offset by an increase in cash outflows for principal elements of lease payments of US$21.2 million, or 90.6%, from US$23.4 million to US$44.6 million due to us leasing the floating production, storage and offloading facility for the full fiscal year in FY22.

Dividends

We have not declared or paid any dividends in the three and a half years ended December 31, 2023.

Financing arrangements

As of December 31, 2023, we had total available liquidity of US$170.4 million, all of which was cash and cash equivalents.

Existing debt facilities

As of December 31, 2023, the only material debt facility we had outstanding was the revolving RBL facility, which we entered into on November 16, 2023. We made an initial drawdown of this facility on December 18, 2023 in connection with the acquisition of interests in the Who Dat assets. To the extent we have available capacity under the RBL facility, we may drawdown this facility for general corporate purposes (other than for the purpose of paying a dividend). For more information about this facility, see “Description of other financing arrangements.”

As of December 31, 2023, this facility had a facility limit of US$340 million, of which we had drawn US$274.0 million. The remaining US$66.0 million under this facility was committed but unavailable due to the current level of reserves in our borrowing base assets. We are currently in the process of incorporating our interest in the Who Dat oil and gas fields into our borrowing base assets, and we expect this process to complete by June 30, 2024. While the process is ongoing and the related calculation remains subject to further confirmation, we expect the committed but unavailable amount under our RBL facility to become available after this process is completed. After March 2026, this facility limit will be reduced on a straight-line basis semi-annually to September 30, 2028. This facility will mature on the earlier of (i) September 30, 2028 and (ii) the date on which the 2P reserves of the borrowing base assets will be equal to or less than 25% of our 2P reserves of the borrowing base assets as of December 18, 2023.

The carrying value of these borrowings, which represents the drawn amount less US$9.6 million of unamortized transaction costs, was US$264.4 million. Our RBL facility bears floating rates of interest calculated by reference to a margin over the Secured Overnight Financing Rate ("SOFR") and a credit adjustment spread. The weighted average interest rate of this facility during TY23 was approximately 9.64% per annum. We are required to enter into hedging arrangements under the RBL facility to mitigate our exposure to movements in oil prices by reference to a minimum and maximum proportion of our forecast production over the next two years. See "– Key factors affecting our results – Oil and gas prices" for more information about our hedging requirements.

We are subject to a number of financial covenants under the RBL facility. For more information about these financial covenants, see "Description of other financing arrangements."

Prior debt facilities

We established a reserve-based, non-recourse, syndicated loan facility in November 2021. In April 2022, we established an additional accordion facility under this loan facility. These facilities were secured over the shares in and assets of the entity that holds our interest in the Baúna concession.

The two facilities combined had a facility limit of US$210.0 million, of which we had drawn down US$30.0 million as of June 30, 2023 and June 30, 2022. The carrying value of these borrowings, which represents the drawn amounts less US$1.9 million and US$2.9 million of unamortized transaction costs, respectively, were US$28.1 million and US$27.1 million as of June 30, 2023 and 2022, respectively. Our borrowings under these facilities bore floating rates of interest originally calculated by reference to a margin over LIBOR before being amended for SOFR in 2022. The weighted average interest rate of these facilities during FY23 and FY22 was 8.22% per annum and 5.95% per annum, respectively. We were required to enter into oil hedging in accordance with minimum and maximum hedge ratios under these facilities. These facilities also included a number of financial covenants, and we complied with all of these while these facilities were on foot.

During TY23, we repaid US$29.9 million of the US$30.0 million we had drawn down under this facility and canceled all other commitments under this facility. As of December 31, 2023, we had US$0.1 million outstanding under this facility. Since December 31, 2023, we have repaid and canceled this remaining balance.

Capital expenditure

We operate in a capital-intensive industry and invest substantial amounts of capital to maintain our operations, develop our growth projects and conduct exploration and evaluation activities. We undertake a phased project maturation process in an effort to de-risk our projects prior to spending material capital. As such, while the majority of capital expenditure for our projects will follow a final investment decision to develop the project, we will also spend significant amounts of time and capital studying the feasibility of these projects in order to determine whether to develop them.

The following table shows our total capital expenditure for FY21, FY22, FY23, HY23 and TY23.

	FY21	FY22	FY23	HY23	TY23
			(US$ million)		
Oil and gas assets[1]	17.4	92.0	190.9	138.6	3.4
Exploration and evaluation	1.9	1.4	44.8	0.5	6.6
Other plant and equipment[2]	6.0	5.0	2.7	2.4	0.7
Total	**25.3**	**98.4**	**238.4**	**141.5**	**10.7**[3]

Notes:

(1) Excludes Baúna acquisition costs, capitalized borrowing costs associated with the Patola development and leased right-of-use asset additions.

(2) Excludes leased right-of-use asset additions.

(3) Excludes the acquisition of asset interests from LLOG.

During FY23, we completed the Baúna workover program, developed the Patola field as a subsea tieback and completed a two well control drilling campaign as part of the Neon discovery. Our capital expenditure related to exploration and evaluation included the expenditure related to our Neon discovery. We funded these projects with cash flows from operations and existing cash on hand, with no further drawdowns from our debt facilities. The Baúna workover program and Patola development involved significant levels of capital expenditure over the three years ended June 30, 2023, and we expect to transition to a less capital intensive operating phase at Baúna going forward. See "Business – Brazil – Producing assets – Baúna – Operational overview" for more information about these two programs. We expect our future capital expenditures to be mainly associated with the Who Dat assets.

We expect to spend US$137 million to US$164 million in capital expenditure during 2024, comprising US$87 million to US$102 million related to exploration work at the Who Dat assets, US$13 million to US$14 million related to exploration work at the Neon discovery and US$37 million to US$48 million related to sustaining capital expenditure.

Off-Balance Sheet Arrangements

Other than as disclosed below under "– Contingent liabilities" and "– Commitments for expenditure," we have no other significant off-balance sheet liabilities.

Contingent liabilities

Letter of credit

We provided ANP a letter of credit to guarantee our performance of a minimum work program in relation to exploration in an exploration tenement in the Santos Basin. We fully funded this letter of credit through the payment of a security deposit, which will be released once the work program is met. There is a risk that we will lose this security deposit should we not satisfy our work program commitments. As of December 31, 2023, the value of the security deposit was US$2.1 million.

Bank guarantees

We have provided bank guarantees in respect of rental agreements for our office premises. These guarantees may give rise to liabilities if we do not meet our obligations under these guarantees. We have fully funded these bank guarantees through the payment of a security deposit. As of December 31, 2023, the value of the security deposits were US$0.2 million.

Cash deposits

We have guaranteed payment obligations to various accommodation providers in Brazil and Peru. We have deposited cash to be held as bonds for our compliance with such obligations. As of December 31, 2023, the value of these cash deposits were US$0.4 million.

Notice of infraction

We have received a notice of infraction from the Santos Municipality for Brazilian real $9.1 million (equivalent to approximately US$1.8 million as of December 31, 2023), inclusive of fines and interest, related to a municipal tax levied on the provision of services on activities carried out by service providers at the *Cidade de Itajaí* floating production, storage and offloading facility. We have rejected the liability and are defending the action.

Block acquisition

As part of our acquisition of Pacific Exploration and Production Corp.'s equity interest in various Santos Basin exploration tenements during the year ended June 30, 2017, we agreed to pay Pacific Exploration and Production Corp. deferred contingent consideration of US$5.0 million payable when 1.0 MMboe is produced from these tenements. We have not provided for this deferred contingent obligation as of December 31, 2023 as it is dependent on uncertain future events.

Brazilian local content

Our concession contracts for a number of Santos Basin exploration tenements require us to acquire a minimum proportion of goods and services from Brazilian suppliers. The minimum requirement under these concession contracts during the exploration and appraisal phase for these tenements is up to 55%. If we fail to comply with this minimum requirement, we may be subject to a fine by the ANP.

Other matters

We are subject to legal claims and exposures which arise during our ordinary course of business. As of December 31, 2023, we do not expect any material loss to result from such claims. For more information, see "Business – Legal proceedings."

Commitments for expenditure

We have entered into contracts for capital and service expenditure in relation to assets and these payment obligations are not provided for in our consolidated financial statements. We also have service commitments which predominately relate to the operating and maintenance contract with OOG-TKP. This services contract has a daily rate for operations payable under the contract. We also have guaranteed commitments for exploration expenditure arising from obligations to governments to perform minimum exploration and evaluation work and expend minimum amounts of money pursuant to the award of an exploration tenement. None of these commitments are provided for in our consolidated financial statements.

The table below sets out these commitments as of December 31, 2023.

	As of December 31, 2023		
	Total	**Less than 1 year**	**Later than 1 year but not later than 5 years**
		(US$ million)	
Capital and service expenditure commitments	**16.1**	16.1	–
Service commitments	**32.1**	16.8	15.3
Exploration expenditure commitments	**27.5**	5.0	22.5
Total	**75.7**	**37.9**	**37.8**

Since December 31, 2023, the respective joint venture partners have approved the drilling of an appraisal well and an exploration well in Who Dat East and Who Dat South, respectively, and we expect the total cost of the two wells to us to be between US$67 million and US$77 million. We expect the capital expenditure for these two wells to be incurred during the year ending December 31, 2024.

These figures do not include any commitments in relation to certain exploration tenements related to the Neon and Goia discoveries. In January 2019, we submitted both a Final Discovery Evaluation Report and Declaration of Commerciality for these discoveries in accordance with Brazilian regulatory requirements. While this transitioned the tenements from the exploration phase to the development phase from a Brazilian regulatory perspective, it does not mean that we have reached, nor are we compelled to reach, a final investment decision with respect to these discoveries. As such, we have not recognized any commitments for expenditure with respect to these tenements.

We estimated our future exploration expenditure commitments based on estimated well and seismic costs, which will change as actual drilling locations and seismic surveys are completed and are calculated in current dollars on an undiscounted basis. Our exploration and evaluation obligations may also vary significantly as a result of renegotiations with the relevant parties. In addition, we may also reduce our exploration expenditure commitments by entering into farm-out agreements or by relinquishing our exploration tenements.

Quantitative and qualitative disclosure about market risk

Our activities expose us to a variety of financial risks including market risk (including foreign exchange risk and interest rate risk), commodity price risk, credit risk and liquidity risk. Our overall financial risk management program focuses on the unpredictability of financial markets and seeks to minimize potential adverse effects on our financial performance. We use different methods to measure the different types of financial risk to which we are exposed. These methods include a sensitivity analysis in the case of foreign exchange, interest rate and commodity prices.

Our Board of Directors, through the audit, risk and governance committee, manages our overall financial risk management strategy. Our strategy is focused on ensuring that we are able to finance our business plans while minimizing potential adverse effects on our financial performance. Our Board of Directors provide written principles for overall financial risk management, as well as written policies covering specific areas, such as mitigating foreign exchange, interest rate, commodity price and credit risks, use of derivative financial instruments and investment of excess cash.

Our finance function carries out financial risk management in accordance with policies approved by the Board of Directors. Our finance function identifies, evaluates and if necessary, hedges financial risks in close co-operation with our chief executive officer. We regularly review our risk management policies and systems to reflect changes in market conditions and our activities.

Foreign exchange risk

Our reporting currency is U.S. dollars. Our revenue, significant operating expenditure including the floating production, storage and offloading facility charter and a large component of capital obligations are predominantly denominated in U.S. dollars. Our foreign exchange risk exposures primarily relate to administrative and business development expenditures which are incurred in Australian dollars and a portion of our operating and capital expenditures related to our Baúna production assets and the payment of Brazilian taxes which are incurred in Brazilian real. We translate these items to their U.S. dollar equivalents at period end and recognize the associated gain or loss in our income statement.

We manage our foreign exchange risk by monitoring forecast cash flows in currencies other than U.S. dollars and ensuring that we maintain adequate Brazilian real and Australian dollar cash balances to meet our requirements. We purchase foreign currencies on the spot market where necessary. Where we purchase foreign currency in advance of requirements, these purchased amounts do not usually exceed the foreign currency amounts we estimate we will need over the next three months. The main exception to this is the Brazilian real we purchase to settle our corporate income tax true up liability, which we accumulate over a 12 month period. We regularly review the appropriateness of our Australian dollar and Brazilian real cash holdings against our expenditure commitments.

We periodically conduct sensitivity analyses to evaluate the potential impact of unfavorable exchange rates on our future financial position. We use the results to determine the most appropriate risk mitigation tool. We will hedge our foreign currency exposures when we deem it to be the most appropriate risk mitigation tool. As of December 31, 2023, we had no material transaction exposures as the majority of our financial assets and liabilities are denominated in U.S. dollars.

Interest rate risk

Interest rate risk is the risk that the fair value of future cash flows of our financial assets and financial liabilities will fluctuate because of changes in market interest rates. We manage this risk through the use of cash flow forecasts supplemented by sensitivity analyses. Our interest rate risk arises from long-term borrowings which accrue interest at floating interest rates and our cash and cash equivalents and security deposits which earn interest at floating interest rates. Our primary exposure is to U.S. dollar interest rates as our long-term borrowings and the majority of our cash and cash equivalents are denominated in U.S. dollars.

The following table sets out our exposure to interest rate risk for financial assets and financial liabilities as of December 31, 2023.

	As of December 31, 2023				
	Floating interest rate	Fixed interest rate	Non-interest bearing	Fair value	Carrying amount
			(US$ million)		
Financial assets					
Cash and cash equivalents	164.5	5.9	–	170.4	170.4
Receivables	–	–	56.4	56.4	56.4
Other financial assets	–	–	0.2	0.2	0.2
Total financial assets	164.5	5.9	56.6	227.0	227.0
Financial liabilities					
Trade and other payables	–	–	73.8	73.8	73.8
Borrowings	274.1	–	–	274.1	274.1
Other financial liabilities	–	222.5	–	222.5	222.5
Lease liabilities	–	–	224.4	224.4	224.4
Total financial liabilities	274.1	222.5	298.2	794.8	794.8

The following table sets out how sensitive our profit/(loss) before income tax and financial instruments would be to a 1% per annum increase or decrease in interest rates as of December 31, 2023. This sensitivity analysis is not fully representative of our inherent interest rate risk, as the financial period end exposure does not necessarily reflect our exposure during the course of a financial period. This is particularly the case here as we only drew down on the RBL facility on December 18, 2023. This sensitivity analysis should also not be used to forecast the future effect of movements in interest rates on future cash flows.

	As of December 31, 2023
Change in profit/(loss) before income tax	
Increase of interest rate by 1% per annum	(1.0)
Decrease of interest rate by 1% per annum	1.0
Change in financial instruments	
Increase of interest rate by 1% per annum	(1.0)
Decrease of interest rate by 1% per annum	1.0

As of December 31, 2023, we had no interest rate hedging in place.

Commodity price risk

We are exposed to commodity price fluctuations due to our production and sale of oil and gas. To mitigate commodity price risk, we have entered into Brent crude oil price hedges utilizing a combination of puts and collar structures consisting of bought put and sold call options. During TY23 and FY23, approximately 26% and 37% of reported production volume was hedged, respectively. As of December 31, 2023, we held hedging instruments with a net asset carrying value of US$0.2 million.

As of December 31, 2023, a 10% increase or decrease in Brent crude oil prices would have had no material impact on the carrying value of our hedging instruments.

As part of our acquisition of Baúna, we agreed to pay Petrobras contingent consideration of up to US$285 million plus interest of 2% per annum accruing from January 1, 2019. We account for the fair value of this contingent consideration arrangement as an embedded derivative and estimate it by calculating the present value of the future expected cash outflows. We make these estimates based on our internal assessment of future oil prices, which considers industry consensus and observable oil price forecasts. The following table details our sensitivity to a 10% increase or decrease in our internal assessment of future oil prices on the contingent consideration payable to Petrobras. As of December 31, 2023, as the US$70 per barrel threshold was triggered over calendar years 2022 and 2026, the maximum contingent consideration payable has already been recognized. As such, a 10% increase in oil price would have no impact on the fair value of the contingent consideration payable to Petrobras.

	As of December 31, 2023
Change in profit/(loss) before income tax	
Increase in oil price of 10%	–
Decrease in oil price of 10%	21.9
Change in financial liabilities	
Increase in oil price of 10%	–
Decrease in oil price of 10%	(21.9)

Credit risk

Credit risk refers to the risk that a counterparty will default on its contractual obligations resulting in financial loss to us. This risk arises from cash and cash equivalents and security deposits held with banks, financial institutions and joint operators, as well as credit exposures to customers, including outstanding receivables and refundable tax credits. To minimize our credit risk, we have adopted a policy of only dealing with recognized and creditworthy third parties and we monitor our credit exposure and the external credit ratings of our counterparties on a periodic basis. See Note 21(c) to our audited consolidated financial statements for TY23 for more information on how external credit ratings of banks and financial institutions impact our choice of cash and cash equivalents and security deposit counterparties. Where commercially practical, we seek to limit the amount of credit exposure to any one bank or financial institution. We also minimize our exposure to bad debts by monitoring our receivables balances on an ongoing basis. We do not hold collateral nor do we securitize our receivables.

In TY23 and FY23, all of our revenues from Brazil and the USA were earned from sales to a single customer. We expect the substantial majority of our revenues from Brazil and the USA to be earned from sales to a small number of customers in future periods.

We have two types of financial assets that are subject to AASB 9's 'expected credit loss' model: receivables and security deposits. Under this model, we will reduce the carrying amount of the relevant financial asset through the use of a loss allowance account and recognize this loss on our income statement. We measure the expected credit loss based on available external credit ratings, historical loss rates and the days past due. While our cash and cash equivalents are also subject to these impairment requirements, we did not consider the identified impairment loss to be significant given the counterparties and/or the short maturity.

We consider our receivables relating to Brazil and Australia to have low credit risk on the basis that there is a very low risk of default and the debtor has a strong capacity to meet its obligations in the short-term. As such, we use a 12-month expected credit loss model measure for any impairment test of receivables. As of December 31, 2023, the loss allowance for receivables recognized during TY23 for receivables was US$0.

Liquidity risk

We manage liquidity risk by ensuring that there are sufficient funds available to meet financial obligations on a day-to-day basis and to meet unexpected liquidity needs in the normal course of business. We place emphasis on ensuring there is sufficient funding in place to meet the ongoing operational requirements of our production activities, exploration, evaluation and development expenditure and other corporate initiatives. We use the following mechanisms to manage liquidity risk:

- preparing and maintaining rolling forecast cash flows in relation to operational, investing and financing activities;
- comparing the maturity profile of financial liabilities with the realization profile of financial assets;
- managing credit risk related to financial assets;
- when necessary, utilizing short-term and long-term loan facilities;
- investing surplus cash only in credit quality banks and financial institutions; and
- maintaining a reputable credit profile.

The following table analyzes the contractual maturities of our financial liabilities as of December 31, 2023. The amounts disclosed in the table are the contractual undiscounted cash flows comprising principal repayments.

	As of December 31, 2023					
	Less than 6 months	**6 to 12 months**	**1 to 3 years**	**3 to 5 years**	**Over 5 years**	**Total**
	(US$ million)					
Financial liabilities						
Non-derivative financial liabilities						
Trade and other payables	67.9	–	5.9	–	–	73.8
Borrowings	0.1	–	91.3	182.7	–	274.1
Lease liabilities	30.0	30.3	119.8	73.2	–	253.3
Derivative financial liabilities						
Contingent consideration – embedded derivative	86.0	–	87.6	58.6	–	232.2
Total financial liabilities	184.0	30.3	304.6	314.5	–	833.4

Critical accounting policies

Critical accounting policies are policies that require us to make significant estimates, assumptions and/or judgments that may significantly affect the reported amounts of assets, liabilities, revenues or expenses. We make these estimates, assumptions and/or judgments based on historical knowledge and best available current information and assume a reasonable expectation of future events based on current trends and economic data obtained both externally and internally. In preparing our consolidated financial statements, we have made a number of judgments and have applied estimates and assumptions to future events.

The following disclosure discusses the estimates, assumptions and/or judgments that we are required to make in the application of those critical accounting policies. For more information about our critical accounting policies, you should refer to the discussion in the notes to our audited consolidated financial statements for TY23 and the discussion of key audit matters referred to in the audit report attached thereto, included elsewhere in this offering memorandum.

Impairment of oil and gas assets

We assess whether our oil and gas assets are impaired on at least a semi-annual basis. If any indication of impairment exists, we will recognize an impairment loss if the carrying amount of an asset or cash-generating unit exceeds its estimated recoverable amount. The recoverable amount of an asset is the higher of the asset's fair value less costs of disposal and value in use.

For our oil and gas properties, the expected cash flow we use in calculating their fair value less costs of disposal is based on our reserves estimate, future production profiles, forecasted commodity prices and estimated costs, all of which are uncertain. The estimates we make with respect to these factors are likely to change from period to period, and we may recognize significant levels of impairment on our income statement as a result of such changes.

Capitalized exploration and evaluation expenditure

We capitalize exploration and evaluation expenditure on the basis that exploration and evaluation operations in the areas of interest have not, at the end of the reporting period, reached a stage that permits a reasonable assessment of the existence or otherwise of economically recoverable reserves, and where active and significant operations in, or in relation to, the areas of interest are continuing.

The future recoverability of our capitalized exploration and evaluation expenditure is dependent on a number of factors that require our judgment, including whether we decide to exploit the related exploration tenement or, if not, whether we successfully recover the related exploration and evaluation asset through sale. Factors that could affect the future recoverability of this expenditure include:

- the level of economically recoverable reserves;
- future technological changes which could impact the cost of development;
- future legal changes, including changes to our environmental and restoration obligations; and
- changes to commodity prices.

All of these factors require us to make estimates, judgments and/or assumptions at the end of each reporting period. To the extent we determine that capitalized exploration and evaluation expenditure will not be recoverable in the future, the relevant amounts will be impaired in our income statement and our assets will be reduced.

Provision for restoration

We recognize a provision for restoration where there is a present obligation as a result of exploration, development or production activities having been undertaken, and it is probable that an outflow of economic benefits will be required to settle the obligation.

We have recognized a provision for our restoration obligations with respect to the Baúna oil field. The calculation methodology we employ in determining our restoration obligations is different from the methodology employed by the ANP. The value of the surety bond we have provided in connection with our existing decommissioning obligations was calculated using ANP's methodology. For more information about this surety bond, see Note 23(c) to our audited consolidated financial statements as of and for TY23. We have also recognized a provision for our restoration obligations with respect to the Who Dat oil and gas fields.

We include in our restoration provision the estimated costs of decommissioning and removing an asset and restoring the site. We base this estimate on judgments and assumptions regarding removal dates, technologies, industry practice and relevant legislation. In determining an appropriate level of provision, we consider the:

- expected future costs to be incurred;
- timing of these expected future costs;
- estimated future level of inflation; and
- appropriate discount rate.

The ultimate costs of restoration are uncertain and we may revise our cost estimates in subsequent years due to many factors including changes to the relevant legal and legislative requirements, the emergence of new restoration techniques and experience at other fields. Any change in our estimates could result in a significant change to the level of provisioning required, which would in turn impact future financial results.

Estimates of reserves quantities

Our estimated quantities of 2P hydrocarbon reserves are integral to the calculation of amortization expense and to the assessment of impairment or impairment reversals.

We estimate reserve quantities based on:

- our interpretation of geological and geophysical models;
- reservoir engineering and production engineering analyses and models; and
- assessments of the technical feasibility and commercial viability of producing the reserves.

Our reserves assessments require assumptions to be made regarding future development and production costs, commodity prices, exchange rates and fiscal regimes. Our estimates of reserves may change from period to period as the economic assumptions used to estimate the reserves can change from period to period. They may also change as additional geological data is generated through the course of operations. Any such changes may impact depreciation, amortization, asset carrying values, restoration provisions and deferred tax balances. If we revise downwards our proved and probable reserves estimates, our earnings could be affected by a higher depreciation and/or amortization charge or the immediate write-down of the carrying value of assets.

Fair value measurement of financial instruments

We measure the fair value of financial assets and financial liabilities using valuation techniques including the discounted cash flow model when they cannot be measured based on quoted prices in active markets. Our calculation of the fair value of our contingent consideration arrangement (as described above) is based on our internal assessment of future oil prices, which considers industry consensus and observable prices, inflation and an appropriate risk-free rate. Any changes in our assumptions relating to these factors could affect the reported fair value of the financial instrument.

Income tax

We are subject to income taxes in Australia, Brazil, the USA and other jurisdictions where we have foreign operations. We undertake many transactions and calculations during the ordinary course of business for which the ultimate tax determination is uncertain. We estimate our tax liabilities based on our understanding of the relevant tax laws. Where the final tax outcome is different from the amounts that were initially recorded, such differences will impact our current and deferred tax balances.

We recognize deferred tax assets to the extent that we think it is probable that sufficient taxable amounts will be available against which deductible temporary tax differences or unused tax losses and tax offsets can be utilized. We offset deferred tax assets and liabilities when there is a legally enforceable right to offset current tax assets and liabilities and when the deferred tax balances relate to the same taxation authority. In calculating the amount of benefits brought to account or which may be realized in the future, we assume that there will be no adverse change in income tax legislation and that we will derive sufficient future assessable income to enable the benefit to be realized and comply with the conditions of deductibility imposed by law.

We make significant estimates related to expectations of future taxable income when assessing the future utilization of tax losses and temporary tax differences. Our estimates of future taxable income are based on forecast cash flows from operations and require us to assume the application of existing tax laws. To the extent that future utilization of these tax losses and temporary tax differences becomes probable, this could result in significant changes to the deferred tax assets recognized, which could in turn impact our future financial results.

Determining the lease term of contracts with renewal options

We determine the lease term as the non-cancellable term of the lease, together with any periods covered by an option to extend the lease if it is reasonably certain to be exercised, or any periods covered by an option to terminate the lease if it is reasonably certain not to be exercised. Our judgment with respect to the term of a lease will significantly influence the level of depreciation and amortization recognized in each reporting period with respect to that lease. See "– Key income statement line items – Cost of sales" and "– Key income statement line items – Finance costs – Finance charges on lease liabilities" for more information.

We have several lease contracts that include renewal options. We apply judgment in evaluating whether it is reasonably certain that we will or will not exercise the option to renew the lease. In making this judgment, we consider all relevant factors that create an economic incentive to exercise the renewal. After the commencement date of a lease, we will reassess the lease term if there is a significant event or change in circumstances that is within our control and affects our ability to exercise the option to renew or to terminate the lease. We included the renewal periods as part of the lease term for the floating production, storage and offloading facility right-of-use asset as there will be a significant negative effect on production if a replacement asset is not readily available.

New and amended reporting requirements

We have adopted the following amendments to accounting standards which became effective for TY23:

- AASB 2021-2 *Amendments to Australian Accounting Standards – Disclosure of Accounting Policies and Definition of Accounting Estimates;*

- AASB 2021-5 *Amendments to Australian Accounting Standards – Deferred Tax related to Assets and Liabilities arising from a Single Transaction*; and

- AASB 2023-2 *Amendments to Australian Accounting Standards – International Tax Reform – Pillar Two Model Rules.*

The adoption of these amended standards did not result in any changes to our accounting policies and has had no effect on either the amounts reported for the current or previous years.

We disclose the Australian Accounting Standards and Interpretations that have been issued or amended but are not yet effective as of December 31, 2023, in Note 1(a) ("New standards and interpretations not yet adopted") to our audited consolidated financial statements as of and for TY23.

BUSINESS

Overview

We are an international offshore upstream oil and gas production and exploration company headquartered in Melbourne, Australia, with assets in Brazil and the United States of America. In Brazil, we own and operate the producing Baúna, Piracaba, and Patola fields, which we refer to as Baúna, and are party to concession agreements, in the Santos Basin. In the United States of America, we own non-operated interests in the producing Who Dat, Dome Patrol, and Abilene oil and gas assets, which we refer to as Who Dat, as well as interests in exploration licences, located in the US Gulf of Mexico. Our assets are diversified geographically with multiple producing wells in the Santos Basin and US Gulf of Mexico, which are prolific, globally recognized hydrocarbon basins providing us with the opportunity to increase our reserves and resources. At December 31, 2023, we had production from six oil fields and 19 producing wells, and eight pre-development and exploration blocks.

Our assets have demonstrated predictable reservoir characteristics and provide us with a high quality marketable product, as reflected in its sales prices. Our assets have relatively low production costs and low sustaining capital expenditure requirements compared to the overall oil and gas sector, resulting in a track record of our assets being highly cash generative with strong levels of free cash flow. We are also able to leverage our technical expertise and experience across our assets.

Our strategy is focused on delivering safe and reliable operations and value accretive growth through investment in our producing assets, development of in-field and near-field opportunities, and acquisitions intended to deliver us a material increase in the scale of our production. We have a track record of safe, efficient operation, and asset enhancement as an operator.

We believe, due to the quality of our existing assets, that our in-field and near-field drilling programs (which are in proximity to our existing producing assets) provide us with the potential to replace and increase our reserves and resources. We have increased production through the delivery of a workover program and development campaign in our Santos Basin assets, which were completed on time and on budget. See also "– Our production and exploration assets – Brazil – Producing assets – Baúna."

We have pursued value accretive growth through our acquisition of Who Dat in December 2023, which was funded through available cash, an equity raise, and drawings from our debt facility. We believe our financial policies are prudent relative to our peers, as evidenced by our low leverage. We are committed to delivering our growth strategy while maintaining financial discipline and a strong balance sheet.

We intend to continue to evaluate acquisition opportunities, focusing primarily on producing assets offshore the United States and Brazil that would increase our production, operating cashflow and profitability. Assets in these geographies would enable us to leverage our presence in Houston and Rio de Janeiro and our technical expertise in the region, as well as potentially providing opportunities to use existing infrastructure. However, we may also examine acquisition opportunities in other locations and at different stages of development.

In the 12 months to December 31, 2023, we generated revenues of US$680.0 million, underlying EBITDA of US$429.0 million, and cash flows from operating activities of US$442.2 million. On a pro-forma basis, assuming we owned the Who Dat assets since January 1, 2023, in the 12 months to December 31, 2023 we had revenues of US$827.4 million and underlying EBITDA of US$548.9 million. See "Unaudited pro forma combined financial information." At December 31, 2023, our PV-10 calculations on a 2P basis, according to AGR and NSAI for our Baúna and Who Dat assets totalled US$2,075 million[22] and we estimated our net oil and gas 2P reserves to be 77.5 MMboe.[23]

22 See "Cautionary note regarding PV-10 values" for further information on our PV-10 figures.

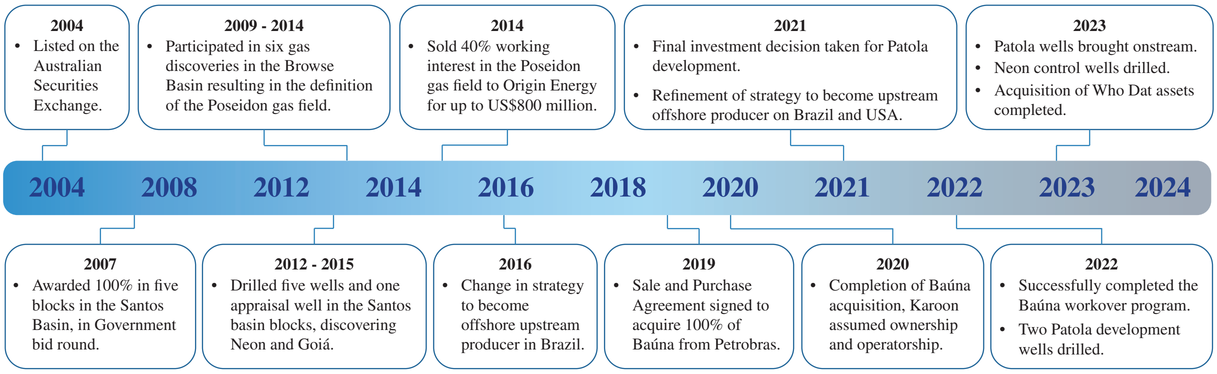
23 For more information on our reserves and resources, see "Cautionary note regarding reserves and contingent resources" and "Reserves and contingent resources."

We are headquartered in Melbourne, Australia, and we have regional offices in Houston, United States of America, and Rio de Janeiro, Brazil. We listed on the Australian Securities Exchange in 2004, and as of April 19, 2024, we had a market capitalization of A$1.7 billion (US$1.1 billion)[24], and employed more than 120 employees.

Company history

In our 20 years since listing on the Australian Securities Exchange, we have grown from our origins as an Australian focused oil and gas explorer to become a diversified oil and gas production and exploration company. We achieved this through the completion of two transformational acquisitions, namely the acquisition of Baúna in 2019 and its subsequent development and expansion, and the acquisition of the Who Dat assets in 2023. At December 31, 2023 we had assets in Brazil and in the United States of America with production from six oil fields and 19 producing wells, and eight pre-development and exploration blocks.

The following chart shows a number of our key corporate milestones.



We were incorporated as a public company under the name Karoon Gas Australia Limited in November 2003. In June 2004 we listed on the Australian Securities Exchange. Our core focus and strategy at that time was to identify, explore and develop prospective oil and gas acreage offshore Australia in the Browse and western Gippsland Basins.

In 2004, we acquired exploration permits in the Browse Basin in Western Australia. We subsequently farmed-out a 60% working interest in these blocks to ConocoPhillips. Under that arrangement, ConocoPhillips committed to fund a major multi-well work and seismic program. From 2009 to 2014, we participated in six gas discoveries from seven wells in the ConocoPhillips-operated Browse Basin exploration campaign, resulting in the definition of the multi-trillion cubic feet Poseidon gas field.

The Santos Basin, offshore Brazil, emerged in the mid-2000s as one of the most active and prospective hydrocarbon basins in the world. Noting this potential and the considerable offshore development being undertaken, in 2007, we participated in a government tender in Brazil, resulting in the award of 100% of the interest in five blocks in the Santos Basin. In 2012, we executed a farm-out agreement for a 35% interest in several of our wholly-owned Santos Basin exploration blocks with Pacific Exploration. We received US$40 million cash as consideration and Pacific Exploration agreed to carry out a multi-well drilling program of up to US$210 million. We subsequently drilled five exploration wells and one appraisal well in the Santos Basin blocks from 2012 to 2015 and made two discoveries, Echidna (Neon) and Kangaroo (Goiá). We assigned contingent resource oil estimates to Echidna (Neon) and Kangaroo (Goiá) in 2015.

In 2014, we sold our 40% working interest in our Browse Basin blocks for an US$600 million upfront cash payment and additional US$200 million in deferred contingent payments, payable by Origin Energy upon meeting certain milestones.

24 A$ translated to US$ at the Reserve Bank of Australia rate for April 19, 2024 of A$1.00 = US$0.6397.

In 2018, we changed our name from Karoon Gas Australia Ltd to Karoon Energy Ltd to reflect our ambitions to hold a diversified asset portfolio.

In 2019, we entered into a sale and purchase agreement with Petrobras to acquire a 100% operating interest in our core production license BM-S-40, located in the Santos Basin. The acquisition was for a headline purchase price of US$665 million, which we subsequently renegotiated during 2020 to include a US$380 million upfront payment, plus potential additional oil price-linked contingent payments of up to US$285 million. We funded this acquisition through a A$284 million equity raising and available cash, and completed the acquisition and assumed ownership and operatorship in November 2020. Baúna, our key Brazilian production asset, is located within the BM-S-40 production license.

In 2021, we took a final investment decision to develop the Patola field within BM-S-40. Patola is adjacent to the Baúna and Piracaba accumulations and is tied back to the existing Baúna floating production, storage and offloading vessel, *Cidade de Itajaí*. For additional information on the Patola development, see "– Our production and exploration assets – Brazil – Baúna."

In October 2021, we announced our refreshed strategy, reflecting our transition from an exploration company to a production and exploration company. At the same time, we strengthened our corporate governance structure and adopted our carbon management action plan. See "– Sustainability – Climate" for further details regarding our carbon management action plan.

Between May and September 2022, we undertook a workover program at Baúna consisting of the installation of new electric submersible pumps and gas lift equipment, leading to a significant production uplift from Baúna compared to when we took operatorship. See "– Our production and exploration assets – Brazil – Producing assets – Baúna – Operational overview."

We drilled two wells in the Patola reservoir in November 2022 and achieved first oil at Patola in March 2023. In January and March 2023, we drilled two control wells in our 100% owned Neon field. These wells captured additional data that resulted in an increase of our contingent and prospective resource estimates.

In December 2023, we completed the acquisition of a 30% non-operated interest in the producing Who Dat and Dome Patrol oil and gas fields in the US Gulf of Mexico. We also acquired an approximately 16% working interest in the producing Abilene field, and varying interests in adjacent exploration acreage. The Who Dat assets are a conventional deepwater oil and gas operation, located in approximately 800 meters of water, offshore Louisiana, which management believes is a high quality, low cost operation. The total consideration for this acquisition was US$720 million. As part of our acquisition, we also agreed to up to US$39.2 million in additional payments relating to the exploration of Who Dat East and Who Dat West. For additional information on our US Gulf of Mexico assets, see "– Our production and exploration assets – US Gulf of Mexico." We funded this acquisition through a A$480 million equity raising, a US$274 million drawdown of our reserve based lending facility (our "RBL facility") and existing cash.

Our strengths

We are a diversified independent oil and gas production and exploration company that is strategically focused on growth in the United States of America and Brazil. Our strategy, which we call "50 for 10", involves us growing our scale to achieve a minimum production of 50,000 boepd which we aim to sustain for no less than a 10 year period. We believe that our high quality assets, technical expertise, experienced board and management, and strong financial position with a robust balance sheet and strong free cash flow will support us in achieving our strategy, and our objective to grow our production and reserves.

We believe that our competitive strengths include:

We are an independent oil and gas company with high quality, conventional, low cost assets with low sustaining capital expenditure requirements and in-field and near-field production growth opportunities.

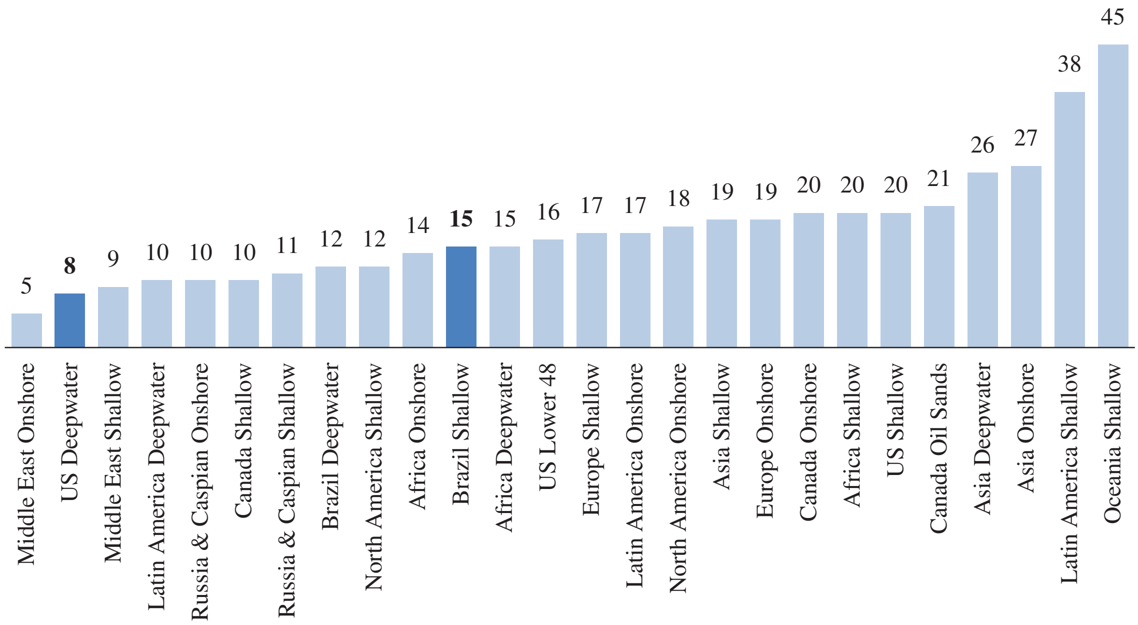
Our assets are conventional offshore assets, which management believes are high quality and low cost and which are in geographic locations that have extensive seismic information. Both the Baúna and Who Dat fields have a long production history and reservoir characteristics that are well understood by our technical teams, comprising our geoscientists and engineers. The predictability of our reservoirs helps us forecast production and cashflows.

Our assets are located in prolific hydrocarbon basins that have proven and well-understood subsurface characteristics. Our assets have in-field and near-field growth opportunities that provide potential to increase our production volumes and reserves, including through potential tie backs to our floating production and storage facilities. Employing tie backs would leverage our existing infrastructure, reducing our capital expenditure when developing assets, enabling us to increase production and reserves in a capital efficient manner and increase our free cash flow generation and profitability.

Our assets have relatively low production costs and low sustaining capital expenditure requirements compared to the overall oil and gas sector. During 2023, Baúna and Who Dat had average unit production costs of US$12.4/boe and US$7.9/boe, respectively. Given our relatively low capital expenditure requirements, on a portfolio basis, our cash breakeven price was US$22.40/boe during TY23.

Wood Mackenzie has prepared the below three-year aggregate unit production costs forecast (including transportation costs). Our unit production costs broadly align with the 'US Deepwater' and 'Brazil Shallow' categories, under which our operations are classified. According to Wood Mackenzie, these provide a proxy for the short-run marginal costs for onstream production across different resource themes and regions, and low operating expenditures reflect greater near-term resilience to commodity price declines for onstream assets.

Wood Mackenzie Unit Production Cost[25] by Resource Theme,
3-yr Aggregate Forecast per Barrel Expenditure 2024-2026



25 Source: Wood Mackenzie; Onstream, commercial liquids fields with remaining liquids resource > 25mmbbl. Unit production costs as defined only include fixed and variable operating expenses, transportation tariffs, and leasing costs. Royalties and G&A expenses are excluded from the unit cost. See "Cautionary note regarding industry and third-party data" and Annex B.

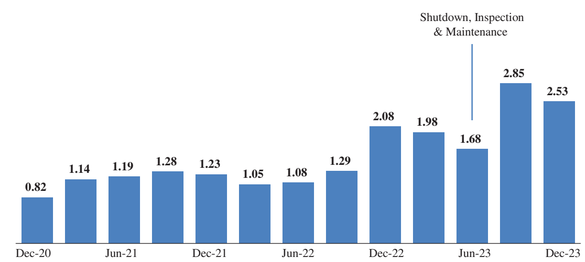
Wood Mackenzie, based on its analysis, considers that absolute demand growth coupled with a forecast supply gap provides a positive environment for long-term oil prices, which it forecasts to range from US$80/bbl to US$84/bbl (in real terms, 2023) between 2025 to 2035. If we are able to maintain our cash breakeven price and Wood Mackenzie's outlook proves accurate, it would allow us to generate strong cash margins and provide us with financial resilience to withstand material downturns in oil prices.

Our producing assets are strategically located in prolific hydrocarbon regions, and have a track record of predictable and efficient production.

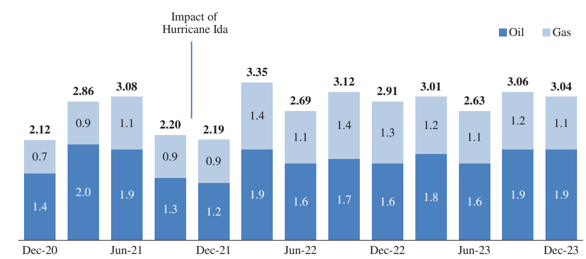
Our assets are located in the Santos basins and the US Gulf of Mexico, two regions that are recognized globally as prolific hydrocarbon basins. We believe that our strategic focus in these regions allows us to realize financial and operational synergies including: (i) the geological properties and reservoir characteristics of our assets are similar, allowing us to leverage our technical expertise and the experience of our geoscientists and engineers across our portfolio, (ii) integration of operating teams and centralization of logistics with proximity of teams located in similar time zones, (iii) synergies in managing supplier and customer relationships, delivering efficiencies and realizing economies of scale due to the increased size of our operations, and (iv) within each region, established infrastructure and pipelines which may reduce development costs and capital expenditure. We believe the strategic location and proximity of our assets contribute to our ability to generate strong free cash flows.

Our assets, which management believes are high quality, have reservoir characteristics that are well understood, and use conventional oil and gas extraction methods, which have historically resulted in predictable production.

Baúna – Quarterly Production History (MMbbl)



Who Dat – Quarterly Production History (MMboe)[26]

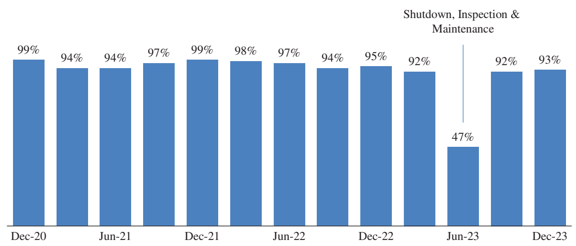


Our Baúna floating production, storage and offloading facility has achieved an average efficiency rate of 95%[27] over the period from November 7, 2020, when we commenced as operator of Baúna, to December 31, 2023. The Who Dat floating production and storage facility has achieved an average uptime rate of 94% since inception, being December 10, 2011 to March 31, 2024. During the quarter ended December 31, 2023, our joint venture partners undertook remediation works for corrosion under insulation on an oil treater degasser, which we use to remove gases from our crude oil, resulting in the lower facilities uptime of 91%.

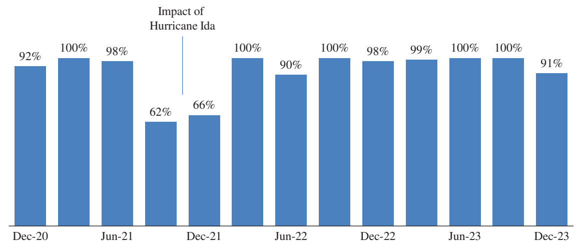
26 Gross production volumes. Source: Historical production data provided by LLOG. During 2021, Hurricane Ida caused 66 days of unplanned downtime as a result of pipeline damage in a downstream facility.

27 Excluding the March 2023 shutdown. See also "Business – Our production and exploration assets – Brazil – Producing assets – Baúna." Including the shutdown, the facility achieved an average efficiency of 91%.

Baúna – Quarterly FPSO Efficiency



Who Dat – Quarterly FPS Uptime

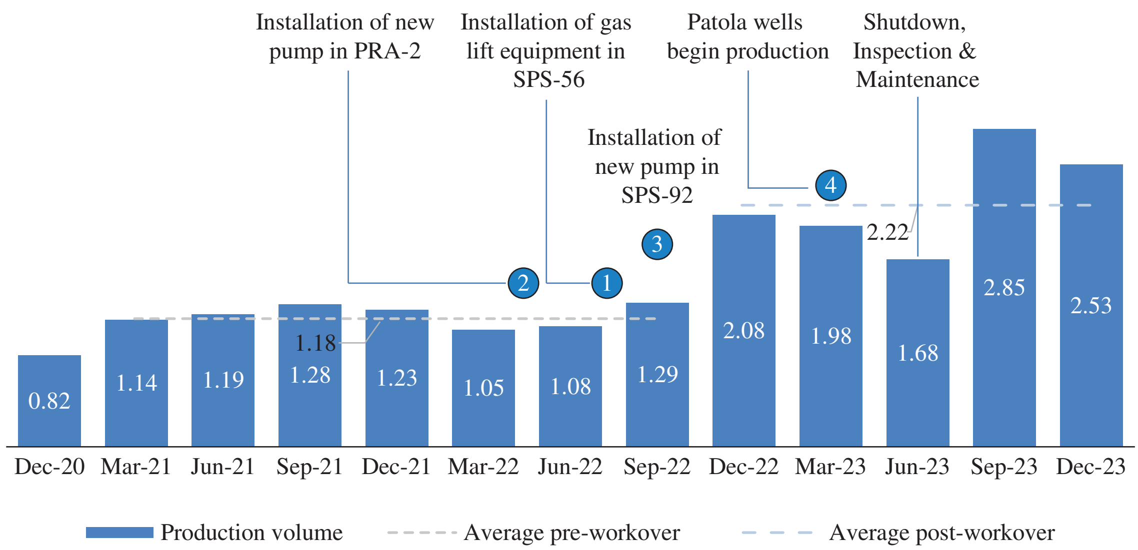


We have a strong track record as an operator, proven history of asset enhancement, and demonstrated technical expertise in the oil and gas industry.

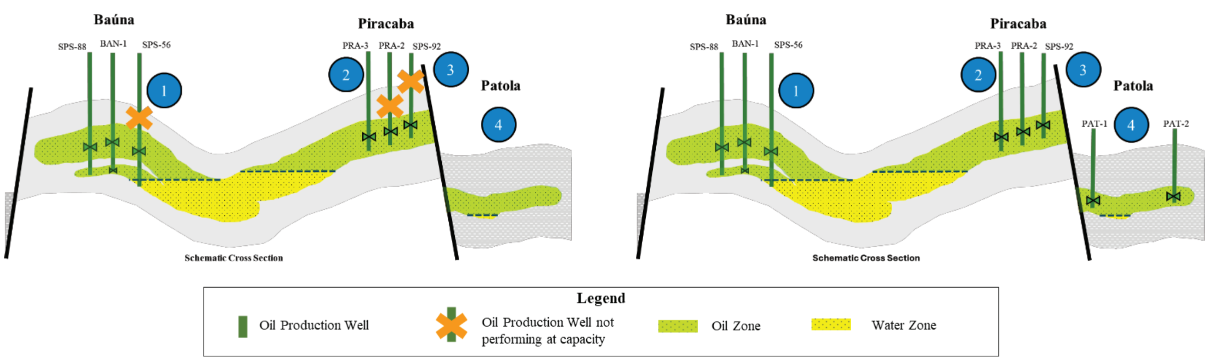
We have considerable experience and technical expertise, and have demonstrated our ability as an operator through our performance at Baúna. Since taking operatorship in November 2020, we have enhanced our asset base, having materially grown production through our workover programs and increased reserves through our in-field and near-field drilling programs. Excluding our six-week shutdown in the first half of 2023, we have also maintained high efficiency rates for the floating production, offload and storage facility at Baúna.

We undertook a workover program at Baúna from May 2022 to September 2022, replacing two electric submersible pumps and installing gas lift equipment, and delivered the development of Patola. This resulted in an increase in our average daily production from 14,600 bopd in March 2021, to a peak average daily production of 34,500 bopd in July 2023. Our workover program and the Patola development increased our 2P reserves by 28.9 MMbbls between December 31, 2020 and December 31, 2022 (not considering reductions through production from Baúna over that same period).

Baúna quarterly production volume (MMbbl)



Baúna assets prior to workover and Patola drilling	Baúna assets after workover and Patola drilling



We have strong relationships with our key business partners, and sell our production through marketing and offtake agreements to investment grade counterparties.

We aim to maintain strong and collaborative relationships with business partners, including our key stakeholders Shell, BP, LLOG and Westlawn.

Offtakers

Brazil – Production offtake arrangements with Shell

- Our production from Baúna is sold under a marketing and offtake agreement with SWST, a wholly-owned subsidiary of Royal Dutch Shell Plc.

- Under the terms of our marketing and offtake agreement, we receive payment from SWST. Shell currently has credit ratings of Aa2 (stable), A+ (stable), AA- (stable), from Moody's, S&P and Fitch, respectively, and is the 5th largest oil and gas company globally by market capitalization.

- We renewed our marketing and offtake agreement with SWST in November 2023, and SWST has been a lender under our RBL facility since October 2019.

US Gulf of Mexico – Production offtake arrangements with BP and Williams

- We sell our share of crude oil from Who Dat to BP Products North America Inc., a member of the BP Plc group under a month-to-month evergreen crude oil purchase agreement. We sell our share of natural gas from Who Dat on a six month seasonal contract basis to BP Energy Company, also a member of the BP Plc group under a gas purchase contract.

- BP Plc, which currently has credit ratings of A1 (stable), A- (positive), A+ (stable) from Moody's, S&P and Fitch, respectively. BP Plc is the 9th largest oil and gas company globally by market capitalization. BP Products North America Inc. and BP Energy Company have parent guarantees from BP Plc.

- We sell our share of natural gas liquids from Who Dat under a life-of-asset sales agreement at prices linked to the Mont Belvieu index as adjusted for the cost of transportation and fractionation to Williams Field Services, a U.S. based natural gas infrastructure provider.

Operators & Partners

Brazil – Altera & Ocyan as owner and operator of the floating production, storage, and offloading facility

- Altera & Ocyan is a joint venture between Brazilian company, Ocyan, and Norwegian-headquartered, Altera Infrastructure, that owns and operates the floating production, storage and offloading facility at Baúna.
- We collaborate with Altera & Ocyan to manage required maintenance and enable continuous production.
- In December 2023, EIG, a global energy and infrastructure investor entered into definitive agreements to acquire Ocyan. EIG has significant investments in infrastructure supporting crude oil production.
- See "Risk factors – Our Brazilian production depends on a single floating production, storage and offloading facility owned by Altera & Ocyan."

US Gulf of Mexico – LLOG as operator and joint venture partner

- Our assets in the US Gulf of Mexico are operated by LLOG, a private independent US operator with extensive technical expertise and experience.
- At the time we acquired our interests in the Who Dat assets, LLOG had advised it had drilled 308 wells in the Gulf of Mexico since 2002, including 116 wells in deep water, and 14 wells at Who Dat.
- LLOG management has a history of performance, and we have a collaborative relationship.

US Gulf of Mexico – Westlawn as joint venture partner

- Westlawn Group is a private investment firm based in Houston, Texas, focused on long-term investment in the oil and gas industry.
- Westlawn is a joint venture partner in Who Dat. Westlawn's management team is well known to us and we have a collaborative relationship.

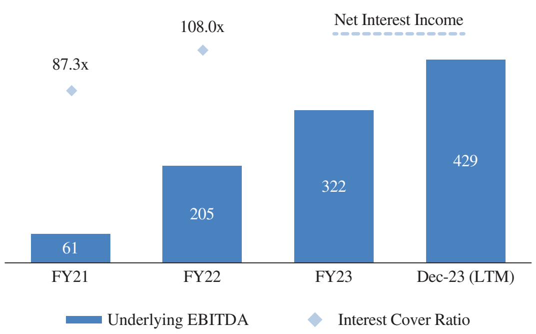
We believe our financial policies are prudent and we have delivered growth while maintaining our financial discipline and a strong balance sheet.

We have a track record of maintaining prudent financial policies and a strong balance sheet. We have maintained low leverage and financial discipline when funding acquisitions such as Baúna in 2019 and Who Dat in 2023. We believe our approach provides us with the flexibility to pursue our growth strategy and the ability to be opportunistic and respond promptly as opportunities emerge in our regions of focus. We consider our balance sheet to be a competitive advantage as it provides sellers with confidence in our ability to complete transactions.

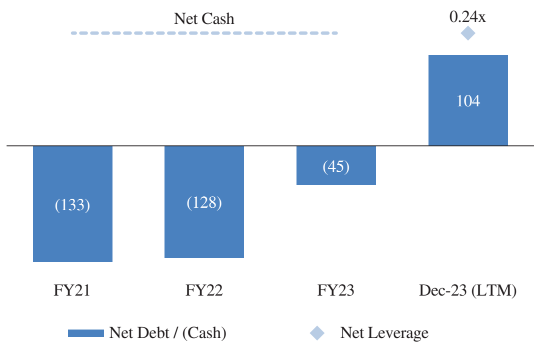
Our financial policies and financial discipline, and our low cash breakeven price of US$22.40 per boe during TY23 provide us with flexibility to remain unhedged (subject to our RBL facility obligations) and retain exposure to movements in oil and gas prices. We consider this important to maximize value for our stakeholders and generate strong free cash flow through the cycle.

We have a Board approved capital allocation framework that prioritizes safe and reliable operations and meeting capital commitments (sustaining capital expenditure, debt servicing, and other mandatory capital commitments). We expect that after meeting these commitments, we will have sufficient cash from our operations to fund growth initiatives and, where appropriate, make distributions to shareholders. In accordance with the capital allocation framework, our goal is to maintain a net leverage ratio of less than 1.0 times through the cycle.

Interest Cover Ratio – Underlying EBITDA/ Net Interest Expense



Net Leverage Ratio – Net Debt/ Underlying EBITDA

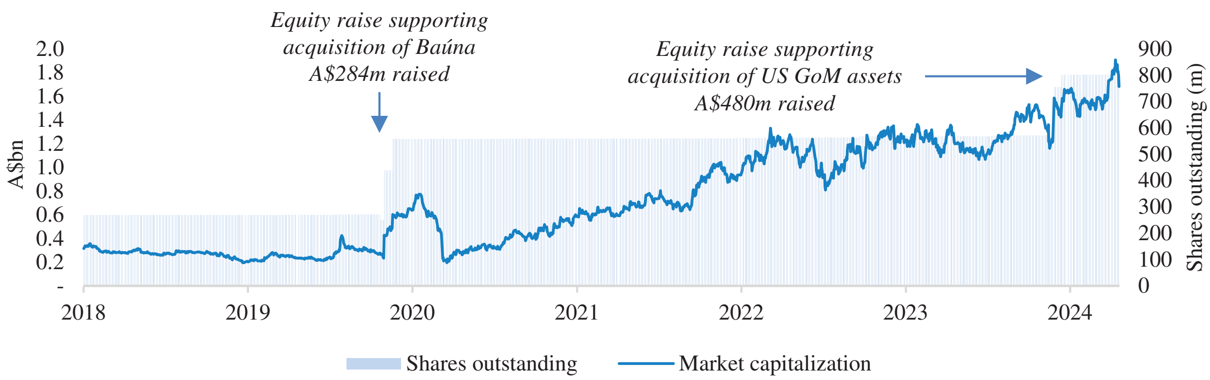


We have benefitted from strong support from capital providers. Our shareholders have supported our equity raisings to fund growth, and we have long term and supportive relationships that lend to us through our RBL facility.

Our capital providers have demonstrated their support and provided us with access to capital to fund growth, in both debt and equity markets, through the acquisition of Baúna, the refinancing of our RBL facility, and the acquisition of Who Dat.

Our shareholder register, at December 31, 2023 comprised approximately 74% institutional investors and 26% retail and other investors. The proportion of our register represented by institutional investors has increased from approximately 42% at the time that we completed the acquisition of Baúna, which we believe is the result of our transition from an explorer to a producing oil and gas company and demonstrates support from the equity market.

Equity Market Support



In respect of our debt relationships and support, in November 2021, we established the RBL facility, a reserve based syndicated loan facility, with total commitments of US$160 million. In April 2022, we increased the total facility limit to US$210 million, with the support of our existing banking relationships. In November 2023, and in anticipation of the acquisition of Who Dat, we completed a refinancing and implemented a new revolving, reserve based lending facility at reduced facility pricing, and on more flexible terms, while increasing the committments under our facility to US$340 million. We expect that when our interest in the Who Dat assets is added to the borrowing base, the full US$340 million committed under the RBL facility will become available, subject to customary conditions to draw. Deutsche Bank, Macquarie Bank, ING and Shell have participated in both of our reserve based facilities. See "Description of other financing arrangements."

We have a strong track record for conducting our operations in a safe, reliable, and environmentally responsible manner, and have ESG policies and procedures designed to achieve our carbon emissions targets.

We have a strong track record for conducting our operations in a safe, reliable, and environmentally responsible manner. We have had no recordable incidents reported over the 12 months ended December 31, 2023. We believe our safety performance is important for all of our stakeholders, and that consistent safety performance supports our long term sustainability as a business and our reputation as a corporate citizen in the markets that we operate.

We also have ESG policies and procedures in place designed to achieve our stated goals for our carbon emission performance. We have been carbon neutral for Baúna since 2021 and aim to be carbon neutral for any acquired assets within five years of purchase, including our Who Dat assets. We aim to achieve net zero by 2035 and have implemented a carbon management action plan designed to help us reach these targets. We have entered into several agreements to purchase externally verified emission reduction certificates, that help offset a portion of our forecast emissions and take emissions into account in our internal decision-making whenever we consider new investments. See "– Our strategy – We intend to continue to operate responsibly and sustainably in accordance with our sustainability strategy and objectives."

We have an experienced board and management team with deep industry expertise.

Our board and management team has significant experience in the international oil and gas industry. The board and management comprises experienced industry veterans that have worked in major oil and gas jurisdictions, including long term experience in Brazil and the United States of America. Our board and management team has guided our transition from an explorer to a producer, delivering the acquisition and development of Baúna and more recently the acquisition of the Who Dat assets.

Our management team have a track record of adding value through acquisitions, developing in-field and near-field opportunities, lowering unit costs of production, improving safety and reliability, delivering our projects on time and on budget, and increasing our reserves. Our team has delivered these outcomes while maintaining a strong balance sheet. Our chief executive officer and managing director, Dr. Julian Fowles has over 30 years of experience in oil and gas operations, including 17 years of working in the upstream sector across the globe. He previously held senior positions with Shell, Cairn India and Oil Search. Our chief financial officer, Ray Church, executive vice president commercial, Stephen Power and executive vice president technical, Roland Hamp, each also have more than 35 years of experience in the resources and energy sector.

We are geoscience and engineering led and focus on delivering growth through robust technical assessment and evaluation. We consider our technical expertise to be crucial to identifying and delivering value accretive growth opportunities.

Our strategy

Our strategy is to be a diversified, independent, offshore oil and gas production and exploration company with a focus on value creation, value accretive growth and prudent balance sheet management in the regions of Brazil and North America. We aim to be carbon neutral while targeting net zero by 2035.

We intend to grow production volumes through acquisitions, targeting opportunities in North America and Brazil, that leverage our technical expertise and teams in these regions.

We have publicly stated our 50 for 10 growth strategy, which we intend to pursue through acquisitions and bringing into production our development assets. Our 50 for 10 strategy is focused on increasing our average daily production to achieve a minimum production rate of 50,000 boepd and sustaining that level of production for a period of no less than 10 years.

We intend to continue to evaluate acquisition opportunities, focusing primarily on producing assets offshore the United States and Brazil that would increase our production, operating cash flow and profitability. Assets in these geographies would enable us to leverage our presence in Houston and Rio de Janeiro and our technical expertise in the region, as well as potentially providing opportunities to use existing infrastructure. Our acquisition of Who Dat is consistent with our strategy. However, we may also examine acquisition opportunities in other locations and at different stages of development.

We are seeking to increase our production scale and longevity and consider that targeting producing and free cash flow generating assets is a lower risk approach that will allow us to achieve these goals over the near- to medium-term. By targeting mid-life assets we are also able to leverage our in-house experience and technical capabilities to allow us to achieve high levels of production efficiency, control costs, and realize value from maturing and under-developed assets. Consistent with our acquisition of Who Dat, we aim to achieve asset life extensions and maximize economic recovery to enable future growth.

We intend to optimize and enhance the production from our existing assets through the development of in-field and near-field growth opportunities to grow our reserves and resources.

We intend to continue to enhance production and reserves from our existing asset base by further exploiting our fields in the Santos Basin and US Gulf of Mexico. Our strategy is to identify and pursue lower risk and higher margin production growth opportunities through leveraging our expertise in well understood geological conditions and maximizing the utilization of our existing infrastructure by pursuing tie back opportunities wherever possible. We have delivered production growth at Baúna through the workover and development programs, and intend to continue optimizing production through workover programs, development drilling, and infrastructure-led exploration which, if successful, can be brought into production relatively quickly and economically.

We intend to progress the potential development of Who Dat East, Who Dat South and Who Dat West, which we believe have the potential to result in a material increase in our production and replacement of our reserves. The joint venture intends to drill an appraisal well at Who Dat East starting in late April 2024. We expect an exploration well to be drilled at Who Dat South in the second half of 2024, and subject to approval by the joint venture partners, a second exploration well to be drilled at Who Dat West, also during the second half of 2024. The Who Dat East discovery and Who Dat South and West prospects, if successful, are expected to be developed through a tie back to the existing Who Dat floating production system, which has the potential to minimize additional capital expenditure requirements, while increasing our production, free cash flow, and profitability. We also continue to examine a range of development options for the Neon discovery in the Santos Basin. During the second quarter of 2024, we approved the progression of the Neon discovery into the "concept select phase", the second stage of our project maturation process.

We will strive to maintain our safety performance.

We have a record of conducting our operations in a safe, reliable, and environmentally responsible manner, and we intend to strive to maintain these standards. The safety of our people is our highest priority and is integral to the sustainability of our business.

To foster a proactive safety culture and shared 'duty of care', we, together with our principal contractors, provide safety inductions, continuous education, and training programs for all workers. We are committed to meeting and, where practical, exceeding the requirements set by relevant laws and regulations in the areas where we operate.

Despite a material increase in exposure hours at Baúna during FY23 as a result of the Baúna workover campaign, the Patola development drilling and control well drilling at Neon, we experienced a total of four reportable safety incidents and injuries during FY23. At the end of March 2024, the Who Dat floating production system facility went through more than 4,550 days since its last reportable safety incident and more than 4,250 days since its last recordable safety incident.

Our Operating Management System reflects our expectations of safety and integrity across our operated assets. The Operating Management System, which encompasses policies, guidelines, and procedures, is regularly reviewed and updated with the aim of ensuring compliance in all applicable jurisdictions.

We intend to continue to operate responsibly and sustainably in accordance with our sustainability strategy and objectives.

We recognize our responsibility to contribute to the communities and environments in which we operate, and the role that industry must play in the reduction of global carbon emissions. We maintain a robust ESG reporting framework and have a sustainability strategy that we intend to continue to execute.

A key aspect of our sustainability strategy is our carbon management action plan. We have been carbon neutral for Baúna since 2021 and aim to be carbon neutral for any acquired assets within five years of purchase, including our Who Dat assets. We aim to achieve net zero by 2035 and have implemented a carbon management action plan designed to help us reach these targets. The first step in our carbon management action plan is to eliminate or reduce emissions. An example of this was the installation of a marine vessel mooring buoy at Baúna which has reduced emissions. The second step with our carbon management action plan is to purchase carbon offsets that fully offset our scope 1 and 2 emissions. In 2022, we entered into agreements to purchase verified carbon units from Shell and Climate Impact Partners and during the second half of 2023, we entered into an agreement to purchase verified carbon units from the Hiwi REDD+ forest conservation project in the Amazon region, operated by Carbonext. The third step with our carbon management action plan is to invest in carbon sequestration projects, with a focus on nature-based solution projects in the country of our operations. We have been closely engaged with several reputable nature-based solution developers in Brazil, and we intend to continue to assess these opportunities as necessary to achieve our target of net zero (Scope 1 & 2 emissions) by 2035, and see value in investing in high quality offset producers, rather than buying offsets, over the longer term.

We intend to maintain our financial discipline and our strong balance sheet as we pursue our growth strategy.

We plan to maintain prudent financial policies and a strong balance sheet with low leverage designed to enable support from our capital providers, with the objective of being able to access capital from both debt and equity markets on reasonable market terms. We believe this approach will assist in supporting the delivery of our growth strategy.

We plan to fund growth through a combination of operating cash flow, debt, and equity where needed and appropriate. We have historically funded our acquisitions in what we believe to be a prudent manner as we did for Baúna where we funded the acquisition through cash and an equity raise, and Who Dat which we funded through cash, debt and an equity raise while maintaining low leverage. We intend to continue our financial discipline and maintaining what we believe to be balance sheet strength, and while also focusing on maintaining liquidity levels, reasonable leverage, while satisfying with our publicly stated capital allocation framework.

Our production and exploration assets

We have two main production assets, comprising six operating oil fields. Our wholly owned and operated producing asset Baúna comprises the Baúna, Piracaba, and Patola oil fields located in the southern Santos Basin, offshore Brazil. Our non-operated interests in the Who Dat producing assets comprises our interests in Who Dat, Dome Patrol, and Abilene oil and gas fields located in the US Gulf of Mexico, offshore Louisiana, United States of America.

In addition to our producing assets, we have various exploration and potential development assets adjacent to our producing Brazil and US Gulf of Mexico assets. These include, amongst others, the Neon and Goiá oil fields, which are located north-east of our Baúna assets in the Santos Basin, offshore Brazil, and are 100% owned by us, and the Who Dat East, Who Dat West and Who Dat South exploration and appraisal opportunities in the US Gulf of Mexico, in which we have a 40%, a 35% and a 30% interest, respectively.

The following map shows our assets and working interests.

Brazil

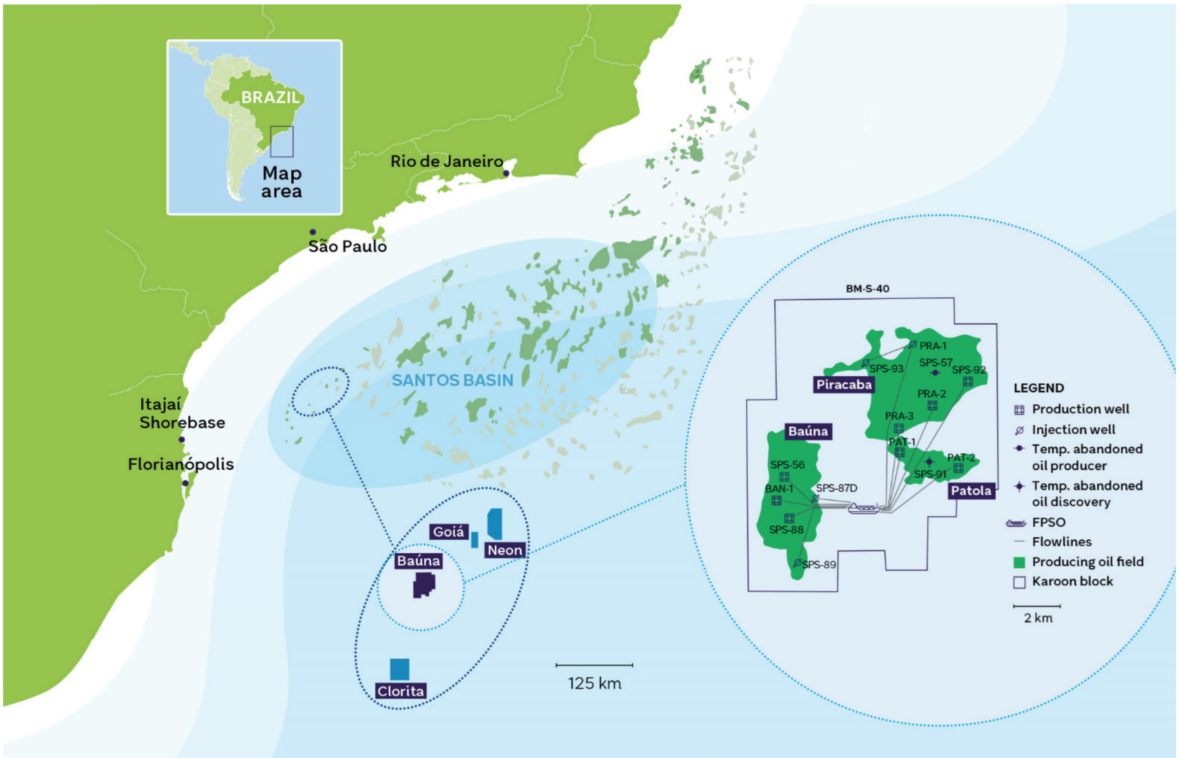
Producing assets – Baúna

Our core producing asset in Brazil is our 100% owned and operated BM-S-40 concession agreement in the southern Santos Basin. The BM-S-40 concession agreement comprises the Baúna, Piracaba and Patola oil fields, all of which are producing. We refer to the Baúna, Piracaba and Patola oil fields collectively as the Baúna Project or Baúna. Baúna is a conventional offshore oil operation, in approximately 300 meters of water, located approximately 210 kilometers offshore Brazil.

Petrobras SA discovered the Baúna and Piracaba fields in 2008. Production commenced in 2013, and in 2019, Petrobras listed the Baúna assets for sale. We acquired and assumed operatorship of Baúna from Petrobras in November 2020 for US$380 million plus additional oil-price related contingent payments of up to US$285 million plus accrued interest. To date, we have paid US$170.5 million of this obligation, which includes US$14.5 million of interest. This acquisition was transformational for us as we evolved from an exploration company to a producer and developer. The transfer of operatorship from Petrobras to us occurred with no material safety incidents or interruption to production.

In February 2022, we entered into a marketing and offtake agreement with Shell Western Supply and Trading Ltd (a member of the Royal Dutch Shell Plc group) or SWST. All of our production from Baúna is sold under this agreement, which we renewed in November 2023. For further details on this agreement, see "– Products, sales, and marketing." We also agreed to acquire emission reduction credits from SWST to offset approximately 60% of FY21 to FY29 Scope 1 and Scope 2 emissions from Baúna. These are verified by global certifier of voluntary carbon offsets, VERRA. As a result of these credits, and previous carbon credits that we acquired in November 2021, our Baúna assets are carbon neutral.

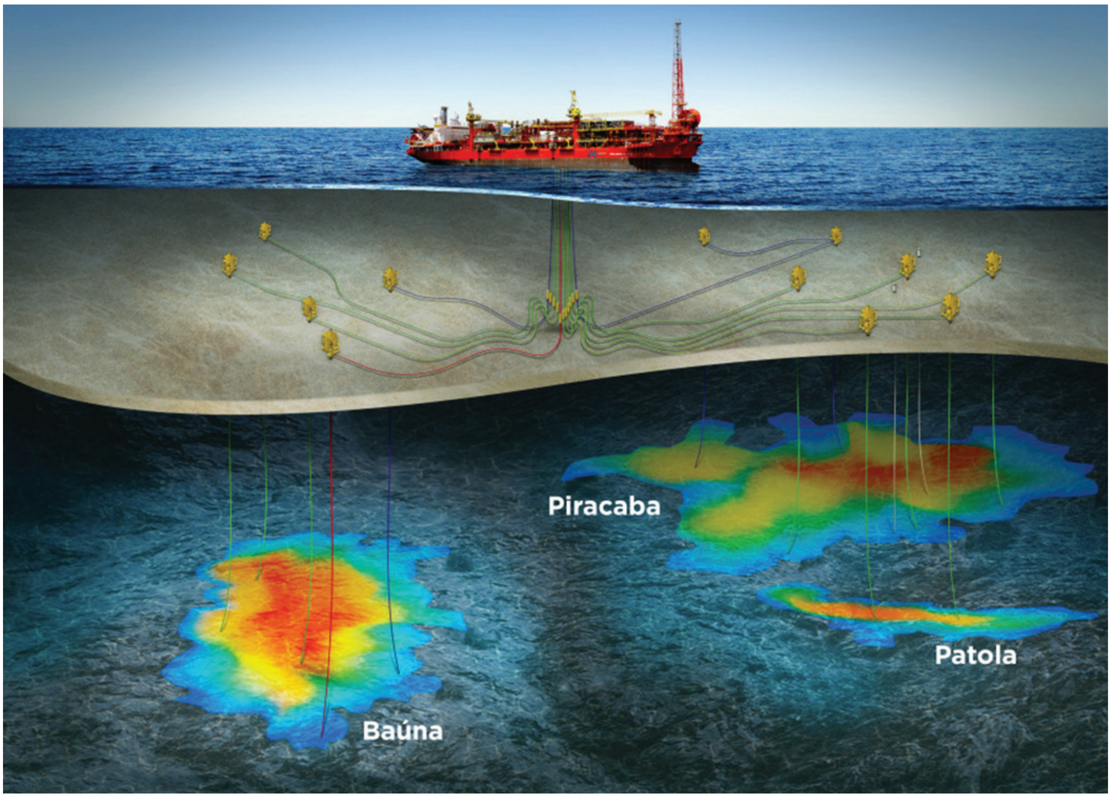
The following map provides a detailed view of our interest in the Baúna assets.



Baúna is located in the southern post-salt region[28] of the Santos Basin and comprises Oligocene reservoirs with high porosity and permeability. See also "Regulatory overview – Regulatory overview – Brazil – Pre-salt and strategic areas." Baúna comprises seven producing wells (and one additional production well that is currently shut in) which are connected through sea-bed flowlines to a floating production, storage and offloading facility, the *Cidade de Itajaí*. The floating production, storage and offloading facility is owned by Altera & Ocyan, a joint venture formed between infrastructure service providers Altera and Ocyan. See "– Floating production, storage, and offloading facility, *Cidade de Itajaí*" below for additional information on the *Cidade de Itajaí*.

28 Post-salt areas overlie an existing salt layer and contain stratigraphically younger hydrocarbon reservoirs compared to pre-salt areas.

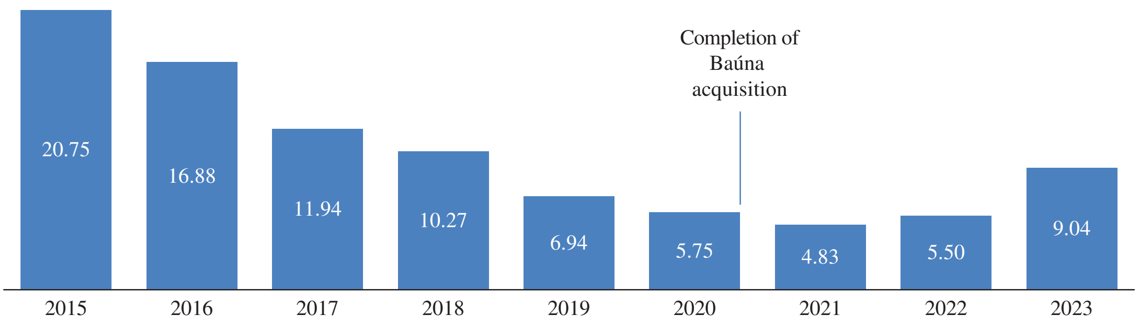
The following graphic shows our Baúna reservoirs, subsea infrastructure and the *Cidade de Itajaí*.



Operational overview

Since taking operatorship in November 2020, we have increased the average daily production rate from 14,800 bopd during the time period from November 7, 2020 to December 31, 2020 to a peak average daily production of 34,500 bopd in July 2023. During the quarter ended December 31, 2023 our average daily production rate was 27,500 bopd, representing an increase by 86% compared to the period from November 7, 2020 to December 31, 2020. The following chart illustrates the long term production profile of Baúna and the improvements achieved due to our investment in Baúna through the workover program and Patola development.

Baúna Production History (MMbbl)[29]



29 Source: Historical data prior to our acquisition provided by Petrobras and as published by ANP.

We identified enhancement opportunities in Baúna which we believed would increase production and reserves and, following 18 months of planning, we undertook a workover program at Baúna from May 2022 to September 2022. The workover program comprised the installation of new electric submersible pumps in two wells (PRA-2 and SPS-92) and the installation of gas lift equipment in a third well (SPS-56). As a result of the workover program, we materially increased production.

In June 2021, we took the final investment decision to proceed with the development of the Patola field. We commenced work after the Baúna oil field workover campaign was completed in September 2022. The Patola development comprised drilling two production wells, installing wellheads and trees and putting subsea production infrastructure in place, including flowlines and umbilicals that connect the wells to the Baúna floating production, storage and offloading facility. We achieved first oil in March 2023, with the Patola development resulting in a material increase in our production and reserves.

We have a track record of delivering enhancements in accordance with our planning, with both the workover program and Patola development being delivered safely, on time, and within budget. The below chart shows the increase in our 2P reserves at Baúna (MMbbl) following our workover and Patola development campaigns.

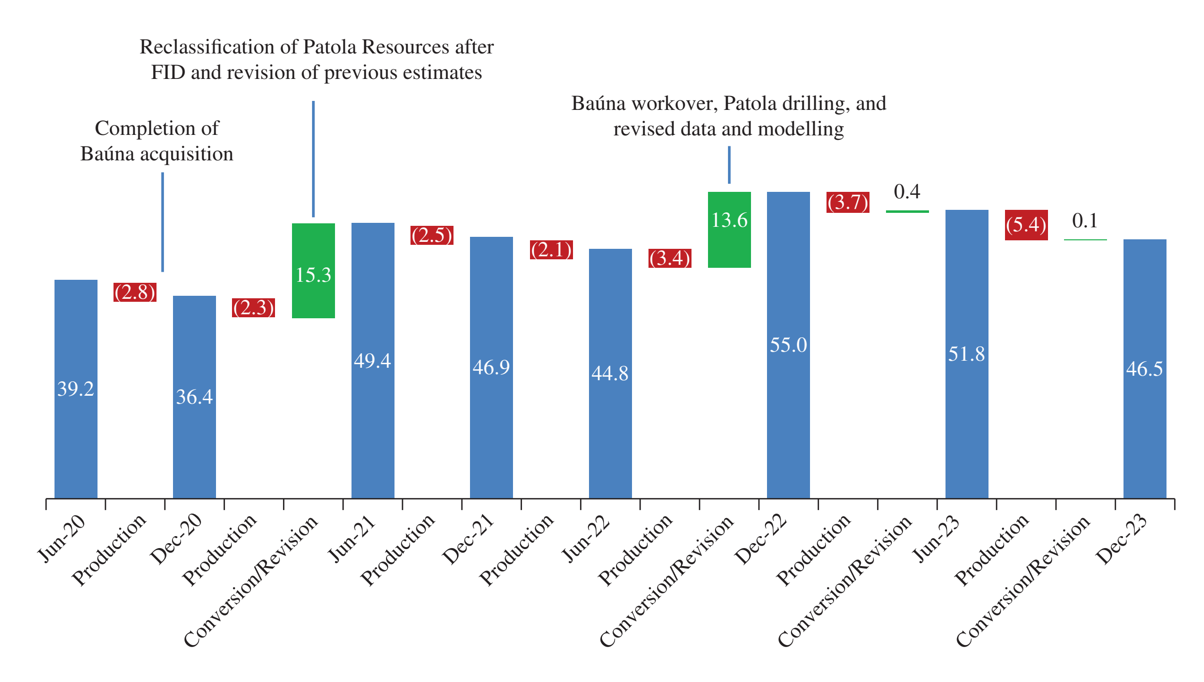
One of our wells at Baúna (SPS-88) has been unable to resume normal production since late 2023 due to a mechanical blockage in the well's gas lift valve. We expect to undertake a workover program in an attempt to return the well to normal production in the third quarter of 2024, subject to regulatory approvals and contracting a suitable vessel.

Floating production, storage, and offloading facility, Cidade de Itajaí

Our floating production, storage, and offloading facility, *Cidade de Itajaí* was built in 1985 and converted to a floating production, storage and offloading facility in 2012. It is owned by Altera & Ocyan and subject to at least annual certification by DNV, a leading classification society and recognized advisor for the maritime industry, and regular review by the relevant regulators.

It has fluid handling capacity of approximately 80,000 barrels of liquid per day and storage capacity of approximately 631,000 bbl of oil. Other than during scheduled shutdowns, operations run 24 hours a day with separate crews working on two weeks on/two weeks off basis. We have technical representatives from Karoon on board the *Cidade de Itajaí* at all times.

Increase in Baúna 2P Reserves (MMbbl)



We have chartered the *Cidade de Itajaí*, until 2026 with two one-year extension options by mutual agreement. We are required to notify Altera & Ocyan one year in advance if we want to exercise these extension options. We have also commenced discussions to extend our contract with Altera & Ocyan until 2032, which is in line with current reserves estimates for Baúna. We are currently assessing whether it is possible to extend the field life of the Baúna assets until 2038 and to commercialize the associated contingent resources we estimate to be present in these fields. Any life extension is subject to contractual negotiations with Altera & Ocyan, and receiving regulatory approvals, including from the Brazilian naval authority and the Brazilian Petroleum Agency, which is our primary regulator and is referred to as ANP. We have assessed potential work required on the subsurface infrastructure and existing wells, and expect to define the scope of any potential life extension project in the second half of 2024.

Our contractual arrangements for the *Cidade de Itajaí* consist of a bareboat charter with Altera & Ocyan and a separate contract for operating services with OOG-TKP, an affiliate of marine transportation company Teekay.

Under the charter, Altera & Ocyan is in charge of the general maintenance of the facility, including in relation to safety equipment, telecommunications systems, the facility's helipad and its insurance. Altera & Ocyan is also responsible for any replacement costs or costs associated with repairs. The costs for our charter are readjusted on an annual basis and tied to the US consumer price index. The charter contract grants us termination rights if, among other circumstances, Altera & Ocyan fails to comply with contractual terms that may significantly impact the performance of the charter agreement or outsources its obligations without our prior written consent. Altera & Ocyan would be able to terminate our charter contract if we had overdue payments outstanding for more than 90 days, subject to certain exceptions, or the operating services contract were to be terminated.

Under the operating services contract, OOG-TKP provides services in relation to the handling, processing and storage of crude oil; supplying of crew, installation of spare parts and maintenance of equipment on board the *Cidade de Itajaí,* water injection, gas lift, gas export and the transfer of stabilized crude oil from the *Cidade de Itajaí* to shuttle tankers. In addition, OOG-TKP is in charge of the implementation and supervision of positioning and ballasting of the facility. The costs for OOG-TKP's operating services are readjusted on an annual basis and tied to the US consumer price index. The operating services contract grants us termination rights if, among other circumstances, OOG-TKP fails to comply with contractual terms that may significantly impact the performance of the agreement, outsources its obligations without our prior written consent or fails to comply with providing proof of the payment of its labor rights obligations. OOG-TKP would be able to terminate the contract if we had overdue payments outstanding for more than 90 days, subject to certain exceptions, we were to suspend the execution of the operating services by written order for a period exceeding 120 days or fail to make the area, location or equipment available that is necessary for the execution of the operating services within contractual deadlines.

Recently, we have been working with Altera & Ocyan to address a range of operational issues with the *Cidade de Itajaí* where we have sought improvements, including adding redundancy to certain systems the failure of which could result in an interruption of production until they are repaired. We have also notified Altera & Ocyan of a number of non-compliances for which we believe we are entitled to receive contractual penalties. While we believe that we and Altera & Ocyan are working constructively to resolve the remaining operational issues, a failure by Altera & Ocyan to address the remaining issues would result in an elevated risk of production interruptions. See also "Risk factors – Risks relating to our industry and operations – Our Brazilian production depends on a single floating production, storage and offloading facility owned by Altera & Ocyan."

We are currently planning to undertake additional enhancements to improve asset integrity, operational efficiency, and emissions in respect of the floating production, storage, and offloading facility, to strengthen our overall performance and sustainability score. We also intend to increase our produced water treatment capacity. The next planned maintenance shutdown has been scheduled for May 2024, during which we plan to conduct an inspection of the valves, tanks and hulls as well as further pipe inspections and integrity activities for up to three weeks.

Production

The following table summarizes key operating and production metrics for our Baúna assets for FY21, FY22, FY23, HY23 and TY23.

	FY21	FY22	FY23	HY23	TY23
Production (MMbbl)	3.14	4.64	7.04	3.37	5.38
Unit production cost (US$/bbl)(1)	25.11	25.36	15.75	17.25	11.09
FPSO efficiency (%)(2)	95%	98%	82%(3)	95%	92%

Notes:

(1) Unit production cost is a non-IFRS figure. See "Non-IFRS financial measures" for further details.

(2) We calculate the efficiency rate of the floating production, storage and offloading facility as actual production divided by our reservoir production forecast, limited to 100%.

(3) In March 2023 following the identification of a gas leak resulting in a temporary shutdown, we decided in consultation with Altera & Ocyan to undertake a comprehensive inspection of the pipework on the floating production, storage, and offloading facility. All identified repairs, maintenance or replacements were conducted over a six-week period, resulting in lower facility efficiency rate in the twelve months ended June 30, 2023.

During FY22 production at Baúna benefited from 98% facility efficiency rate. We produced 4.64 MMbbl from our Baúna assets in FY22, compared to 3.14 MMbbl in FY21. This increase reflected our first full year of operations since the acquisition of Baúna in November 2020.

As a result of the completion of the Baúna oil field workover campaign and the development of Patola, oil production was 52% higher at 7.04 MMbbl in FY23 compared to 4.64 MMbbl in FY22, despite the six-week unplanned shut down of the production facility. Both the workover and the Patola development delivered incremental production above expectations, resulting in a peak average daily production of 34,500 bopd in July 2023.

The facility efficiency rate during FY23 was 94% over the first nine months of FY23. In March 2023, we had to shut down production on the floating production, storage and offloading facility, due to a hydrocarbon leak from pipework located within the facility's gas flaring system. We were able to rapidly isolate and repair the leak but decided, together with the facility operator, Altera & Ocyan, to undertake a comprehensive inspection of the facility's hydrocarbon processing system pipework. We subsequently inspected a total of 783 pipes and valves repaired or replaced more than 120 parts over a six-week shutdown period. We notified ANP, about the gas leak and repair campaign. ANP was supportive of the production restart in May 2023. Our floating production, storage, and offloading facility has historically achieved high levels of efficiency, averaging 95% over the period from November 7, 2020, when we commenced as operator of Baúna, to December 31, 2023, excluding the March 2023 shutdown, and 91% including the shutdown. Despite our production shut down from the end of March 2023 until May 2023, we produced 7.04 MMbbl from our Baúna assets in FY23.

During TY23, our facility efficiency rate was 92% and we produced 5.38 MMbbl of oil from Baúna compared to 95% and 3.37 MMbbl of oil during HY23.

Products, sales, and marketing

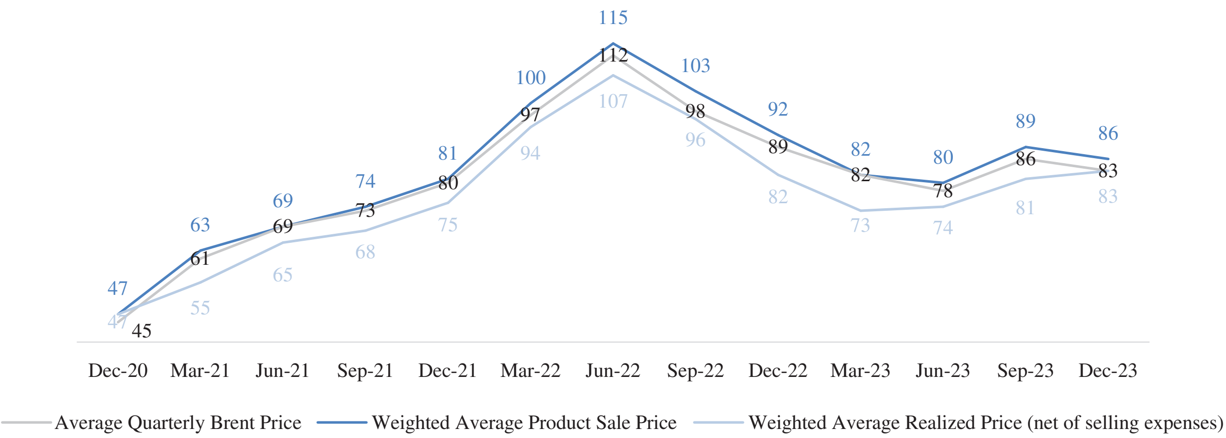
Baúna produces a light sweet crude oil that is high quality, as reflected in its sales prices, with an API between 33 and 38 degrees. Our production is sold to SWST under our offtake and marketing agreement, is then marketed by SWST, and typically sold to a range of customers in South America, North America, Europe and Asia. We realize a price equal to the published Brent crude oil price at the time of sale, adjusted for a negotiated price differential and freight logistics and associated costs. Since acquisition of Baúna, we have averaged a sale price of approximately US$84.92 per bbl which represents a premium to the average Brent price on a delivered basis and which corresponds to an weighted average realized price (net of selling expenses) discount of 4.7% to Brent over the corresponding period.

Our agreement with SWST will expire on the later of (i) the date on which we cancel all commitments under our RBL facility, (ii) three years after the end of the "Pre-Existing Term", which is the later of December 9, 2025 or the delivery of 28.6 million barrels of oil pursuant to the agreement, and (iii) when a further 20.0 million barrels of oil have been delivered pursuant to the agreement after the end of the Pre-Existing Term. As of March 31, 2024, 21.9 million barrels of oil have been delivered pursuant to this agreement. Following an amendment to our offtake and marketing agreement with SWST during TY23, SWST may require us to undertake our own oil transportation activities. If this occurs, the freight logistics charges that are netted against our revenue will be reduced, though our cost of sales would increase.

Under this agreement, SWST is required to use reasonable endeavors to maximize the price payable to us. Each party can terminate the agreement if the other party commits a fraudulent or an unremedied willful breach of the agreement or fails to satisfy a payment demand for more than 28 days after provision of a notice of default.

The chart below shows the average quarterly published Brent crude oil price, our average sale price and our weighted average realized price (net of selling expenses), each in US$/bbl.

Average Quarterly Brent Price, Weighted Average Product Sale Price, and Weighted Average Realized Price (net of selling expenses) (US$/bbl)[30]



Since our acquisition of Baúna, we have sold more than 45 cargoes, to 11 refineries that are located across four continents. Our strategy involves continuing to develop the global market for Baúna crude so as to optimize our realized price.

The crude oil is either offloaded from the Baúna floating production, storage and offloading facility into SWST-operated shuttle tankers and transported to Uruguay or directly transferred by us to SWST through a ship-to-ship oil transfer in the Port of Santos, Brazil.

The following table summarizes key sales metrics for our Baúna assets for FY21, FY22, FY23, HY23 and TY23.

	FY21	FY22	FY23	HY23	TY23
Sales volume (MMbbl)	2.90	4.54	7.06	3.41	4.97
Weighted average realized oil price (net of selling expenses) (US$/bbl)	59.00	84.74	80.20	87.86	82.22
Revenue (US$ million)	170.8	385.1	566.5	299.4	409.1

30 The average Brent price for the quarter ended December 31, 2020 reflects the average published Brent crude oil price over the quarter ended December 31, 2020, noting that our operations commenced on November 7, 2020. We shipped our first cargo in December 2020. Karoon realized price is defined as weighted average realized price (net of selling expenses). Product sale price is defined as the weighted average actual price achieved for Baúna crude based on an agreed premium or discount benchmarked to the Brent crude oil price.

We lifted nine oil cargoes from our Baúna assets in FY22, totaling 4.54 MMbbl, compared to six cargoes lifted in FY21, totaling 2.90 MMbbl. This increase reflected our first full year of operations since the acquisition of our Baúna assets in November 2020 and high facility efficiency rates. In FY22 we realized a weighted average realized price (net of selling expenses) of US$84.74/bbl, compared to US$59.00/bbl in FY21, due to stronger global crude oil prices and the expansion of buyer markets for Baúna crude, which since include Europe, Asia and North and South America.

We lifted 15 oil cargoes from our Baúna assets during FY23, totaling 7.06 MMbbl, representing an increase of 52% compared to FY22. The weighted average realized oil price (net of selling expenses) during FY23 was US$80.20/bbl, compared to US$84.74/bbl in FY22, reflecting weaker oil demand due slowing global economic growth.

We lifted 10 oil cargoes from our Baúna assets during TY23, totaling 4.97 MMbbl. We realized a weighted average realized oil price (net of selling expenses) of US$82.22/bbl during TY23, compared to US$87.86/bbl in HY23, reflecting strong demand for Baúna light sweet crude, with cargoes sold to various refineries in Europe, Asia and North and South America.

Licensing and royalties

The BM-S-40 concession agreement grants us exploration and production rights for our Baúna assets until 2039. We pay royalties to the Brazilian federal government. These are divided into three tiers, 10%, 7.5% and 5% and based on a monthly baseline production decline model approved by ANP. See “Regulatory overview – Regulatory overview – Brazil – Concession bids – Government participation.” During the initial period of our concession agreement, our royalties were set at 10% of our production. Since October 2022, our rates vary between 5% and 7.5% of production. For our Brazilian assets, royalties paid are deducted as part of our cost of sales. See “Management’s discussion and analysis of financial condition and results of operations – Overview – Key income statement line items – Cost of sales.” In addition, we pay a special participation fee on a quarterly basis when production in any given quarter exceeds 300,000 m^3. If we reach this trigger, we are also required to invest 1% of our gross revenue for the quarter into research and development. In the quarter ended December 31, 2023, our production on a cubic meter basis was 416,670 m^3.

Baúna reserves and contingent resources

The following tables sets forth our 1P, 2P and 3P net oil reserves and our 2C contingent resources for our Baúna assets as of December 31, 2023.[31] For additional information on our reserves and resources, see “Cautionary note regarding reserves and contingent resources” and “Reserves and contingent resources.”

Reserves

	As of December 31, 2023		
	1P	2P	3P
		(MMbbl)	
Baúna, Piracaba and Patola	37.1	46.5	55.8
Total (MMbbl)	**37.1**	**46.5**	**55.8**

31 We engaged independent experts AGR Energy Services AS, or AGR, and Netherland, Sewell & Associates, Inc., or NSAI, to deliver independent reserve reports for Baúna and for the Dome Patrol and Who Dat oil and gas fields, respectively, as of December 31, 2023. Summaries of those reports have been included in this offering memorandum in Annex A. As of December 31, 2023, AGR’s estimate of our 2P reserves in Baúna was approximately 2.5% lower than our estimate of 2P reserves. We have relied upon NSAI’s audit report in preparing our estimates of our share of reserves and contingent resources from the Who Dat assets, and any differences between our estimates and the estimates presented by NSAI relate to differences in oil price forecasts. As of December 31, 2023, NSAI’s estimate of our share of 2P reserves from the Who Dat assets was approximately 0.6% lower than our estimate of 2P reserves. We believe that the differences between our reserves estimates and those of AGR and NSAI reflect differences in reasonable professional judgment in interpreting data and applying assumptions and are not material. See “Cautionary note regarding reserves and contingent resources” and “Reserves and contingent resources.”

2C Contingent resources

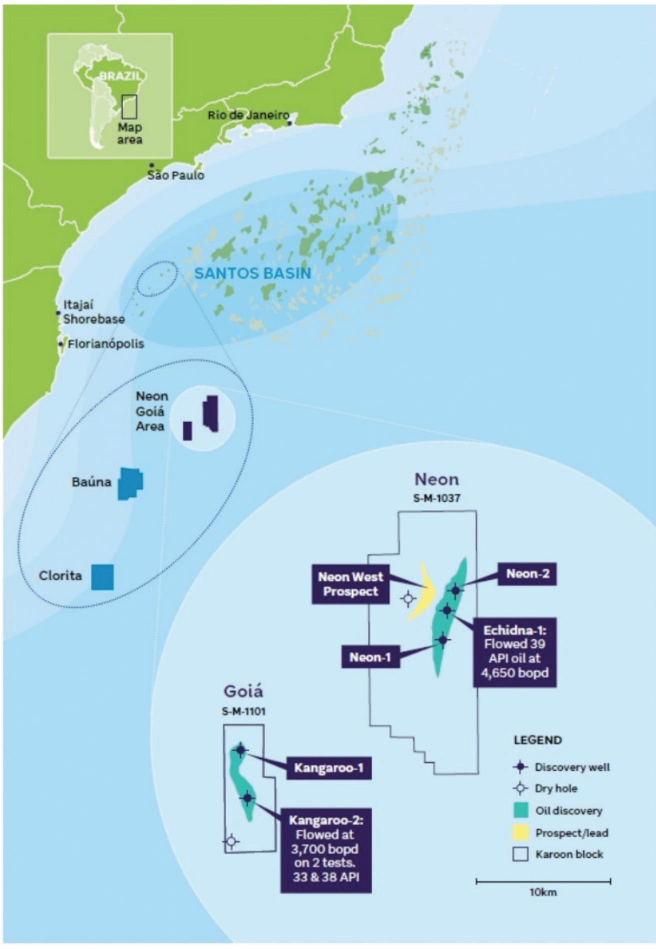
	As of December 31, 2023
	2C
	(MMbbl)
Baúna, Piracaba and Patola	10.9
Total (MMbbl)	10.9

As of December 31, 2023, we had committed a minimum of US$27.5 million towards future exploration activities in connection with our Baúna assets. We also continue to explore and add reserves in our other Brazil operations. See also "Management's discussion and analysis of financial condition and results of operations – Off-balance sheet arrangements – Commitments for expenditure."

Development and exploration assets

In addition to Baúna, we also own and operate several development and exploration blocks in the Santos Basin. These include block S-M-1037, which contains the discovered Neon oil field and the Neon West prospect, and block S-M-1101 which contains the discovered Goiá oil field, both of which are located north-east of Baúna. We also 100% own and operate block S-M-1537, which contains the Clorita prospect, south of Baúna, and in December 2023, we successfully participated in a government bid round to acquire 100% interests in two deepwater blocks, S-M-1356 and S-M-1482, southeast of Baúna. We expect the Brazilian government to formally grant these two blocks to us during the second quarter of 2024. We hold 'Operator A' status in Brazil, as confirmed by the regulatory authorities, which certifies us as meeting the requirements to drill in deepwater blocks.

The following map shows the location of our development and exploration assets in Brazil.



Neon

Neon (formerly known as Echidna) is located 60 kilometers north-east of the Baúna oil field in block S-M-1037 in the Santos Basin, which we were awarded through a government tender in 2007. We discovered Neon with the Echidna-1 exploration well in 2015. The discovery well encountered 100 meters of oil-bearing reservoir and on test, flowed 4,650 bopd of 39 degrees API oil. During April 2024, we approved the progression of the Neon discovery into the "concept select phase", the second stage of our project maturation process.

Following successful tests during initial exploration, we conducted substantial analysis, engineering and technical work on a potential development of Neon in order to assess the commercial potential of the discovery. We drilled two control wells at Neon in January 2023 and March 2023 with both wells intersecting hydrocarbon-bearing reservoirs consistent with pre-drill expectations. This result has reduced our uncertainty around key reservoir parameters. The Neon-1 well confirmed 39 degrees API oil and oil-water contacts closely aligned to our seismic predictions, the Neon-2 well confirmed 33 degrees API oil and thickened reservoir sections in cross-fault and northwestern regions.

As a result of the confirmed Neon-1 and Neon-2 oil discoveries, we reassessed our volume estimates, resulting in a 9% increase in our estimates of Neon's 2C contingent oil resources in FY23. We are currently conducting the technical and commercial feasibility studies for a potential Neon development. The technical aspects include detailed subsurface modelling, integrating seismic reprocessing, core and fluid sample analyses.

We believe that the undrilled Neon West prospect is structurally and stratigraphically analogous to Neon. We have estimated prospective resources for the Neon West prospect due to its close proximity to the Neon discovery and its higher probability of technical and commercial viability in the event of resource confirmation.

The following table sets forth our 2C contingent resource estimates for our Neon oil field as of December 31, 2023. For additional information on our reserves and resources, see "Cautionary note regarding reserves and contingent resources" and "Reserves and contingent resources."

Contingent resources

	As of December 31, 2023
	2C
	(MMbbl)
Neon	60.1
Total (MMbbl)	60.1

Goiá

Goiá is located 10 kilometers south-west of Neon and 50 kilometers north-east of Baúna in block S-M-1101 in the Santos Basin. We were awarded a 100% interest in the block through participation in a government tender in 2007. We discovered oil accumulation through our Kangaroo-1 exploration well in 2013 and appraised it with an additional well (Kangaroo-2) which spudded in November 2014. Initial tests for the Kangaroo wells showed the potential for high initial flow rates of 33 and 39 degrees API oil. As a result of these tests, we were able to assign contingent resource estimates to Goiá in 2015.

We are currently evaluating the Goiá oil discovery, together with nearby opportunities, such as Neon West.

The following table sets forth our 2C contingent resource estimates for our Goiá oil field as of December 31, 2023. For additional information on our reserves and resources, see "Cautionary note regarding reserves and contingent resources" and "Reserves and contingent resources."

Contingent resources

	As of December 31, 2023
	2C
	(MMbbl)
Goiá	27.0
Total (MMbbl)	27.0

Clorita

Clorita is located 50 kilometers south of our Baúna in block S-M-1537 in the Santos Basin. We hold a 100% equity interest in the block. We are currently undertaking desktop geological and geophysical studies, including petroleum system modelling, aimed at better defining the Clorita prospect. We hope to find the same quality Oligocene oil-prone turbidite reservoirs as the Baúna field.

In addition, we are evaluating the potential value of resistivity based 'controlled source electromagnetics' methods to help identify possible reservoir intervals.

S-M-1356 and S-M-1482

We successfully bid for a 100% interest in two deepwater blocks, S-M-1356 and S-M-1482, in the Santos Basin in December 2023. These two blocks lie approximately 80 kilometers southeast of Baúna. Formal granting of these two blocks is subject to certain conditions that we expect to meet during the second quarter of 2024.

United States of America

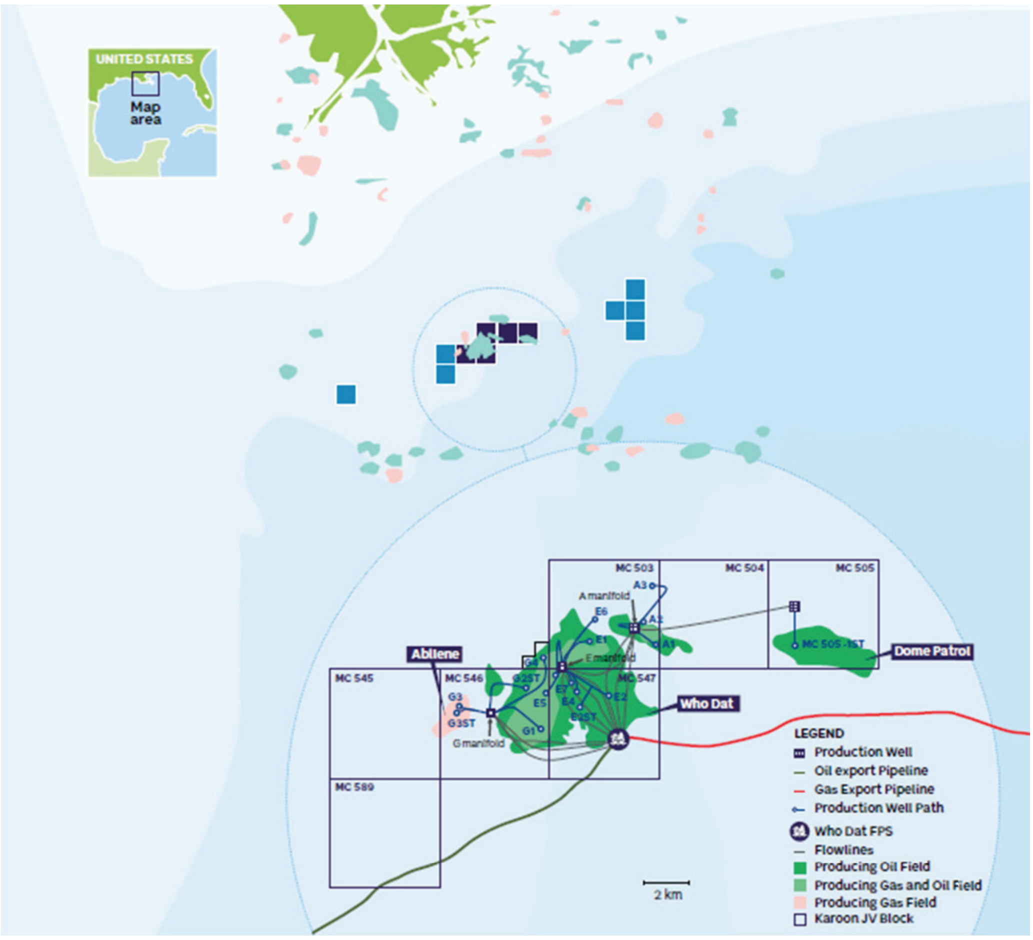
Producing assets – Who Dat

Our core producing asset in the United States of America is our 30% non-operated interest in the producing Who Dat and Dome Patrol oil and gas fields, and approximately 16% working interest in the producing Abilene field. We refer to the Who Dat, Dome Patrol, and Abilene oil and gas fields collectively as Who Dat, or the Who Dat assets. The Who Dat assets are a conventional deepwater oil and gas operation, located in approximately 800 meters of water, offshore Louisiana, which management believes is a high quality, low cost operation.

LLOG acquired its initial interest in the Who Dat field in 2005 and began drilling the first Who Dat well in 2007. A final investment decision was taken in 2010 and initial production started in 2011. We acquired our working interest in the Who Dat assets from LLOG in December 2023 for US$720 million. As part of our acquisition of the Who Dat assets, we also acquired varying interests in adjacent acreage, including the Who Dat East (40% interest), Who Dat West (35% interest) and Who Dat South (30% interest) exploration and appraisal opportunities and agreed to fund up to US$39.2 million in additional payments relating to the appraisal and exploration of Who Dat East and Who Dat West. We funded this acquisition through a A$480 million equity raising, a US$274 million drawdown of our RBL facility and existing cash.

We completed the acquisition on December 21, 2023 and have included our share of production from the Who Dat assets in our production figures from that date. Under the agreement under which we purchased our interests, we agreed to an effective date of October 1, 2023, coinciding with the annual operating plan cycle. This meant that the purchase price was adjusted to give us the economic benefits and obligations of ownership from October 1, 2023 onwards, including revenue, operational expenses and capital expenses. We were entitled to our share of production and participated in joint venture cash calls from December 21, 2023 onwards.

The following map shows the location of our US Gulf of Mexico assets in the United States.



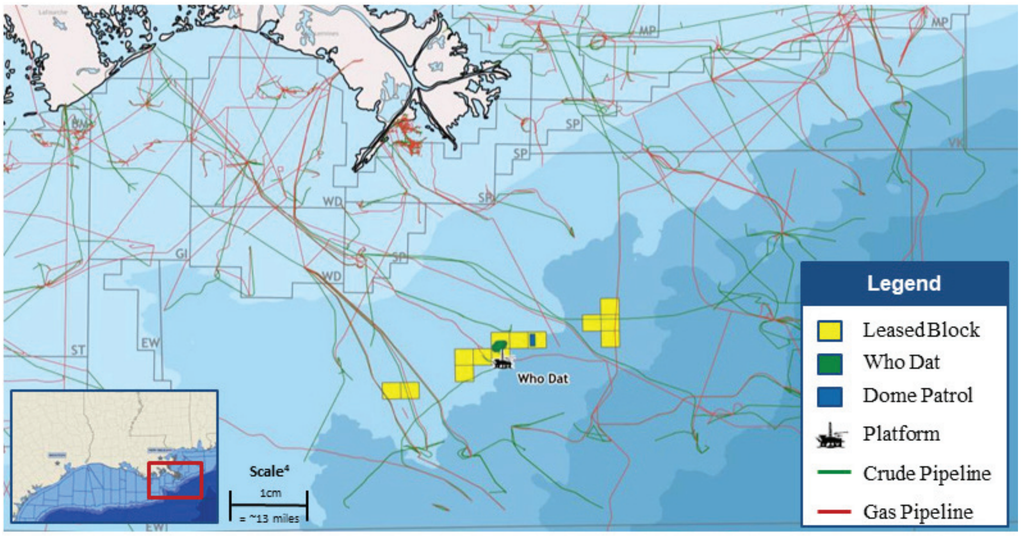
The producing Who Dat assets are located in the Mississippi Canyon blocks 503, 504, 505, 546 and 547. The Who Dat subsea infrastructure includes 13 producing wells, connected to four manifolds, of which three are in the Who Dat field and one at the Dome Patrol field, with associated flowlines. These include smart completions connected to the floating production system facility via umbilicals. Two lateral export pipelines connect to the Mars pipeline for oil and the Canyon Chief pipeline for gas, through which the oil and gas is transported onshore for sale.

All three fields produce through the Who Dat platform, which is a floating production system semi-submersible moored around 800 meters deep offshore in Mississippi Canyon block 547. The floating production system facility has a nameplate capacity of 40,000 bopd and 150 MMscfpd. The Who Dat floating production system historically has had a stable and reliable operating profile. Since commercial production began in 2011 to March 31, 2024, based on the proportion of days with recorded production in the year and excluding scheduled downtime, the facilities have achieved an average uptime of 94%. During the quarter ended December 31, 2023, the joint venture partners undertook remediation works for corrosion under insulation on an oil treater degasser, resulting in a lower facilities uptime of 91%.

The leases for most of our producing Who Dat assets are held-by-production, which means that our joint venture can continue with drilling and production activities as long as we are meeting required minimum production limits. See also "Regulatory overview" and "– Our concession agreements and leases."

Within the United States, the Gulf of Mexico is expected to account for approximately 17% of total crude oil production in 2024 and approximately 8% of all offshore liquids produced globally. As such, it has extensive existing infrastructure, which allows hydrocarbons to be extracted at a comparatively low CO_2e/boe[32].

The following map shows the US Gulf of Mexico and its surrounding infrastructure.

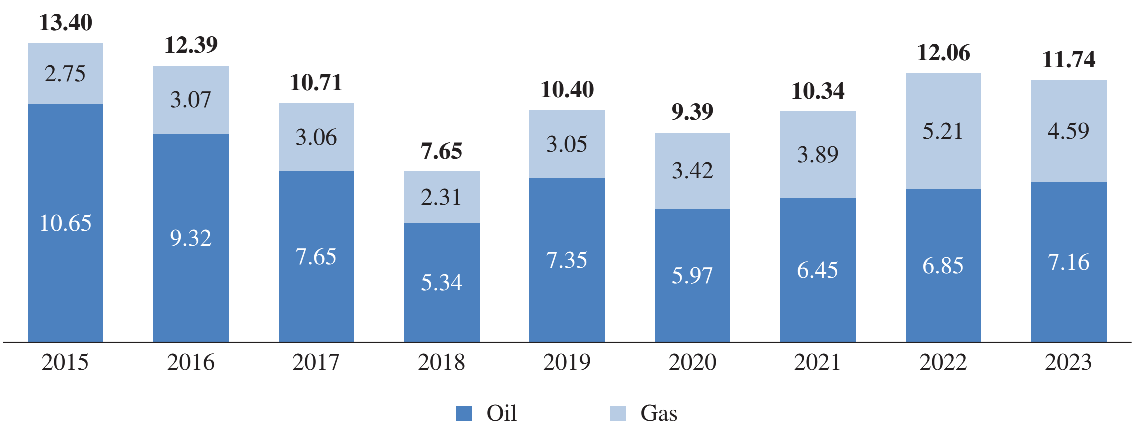


Operational Overview

The subsurface geology of the Who Dat assets is defined by high quality turbidite reservoirs, high porosity and permeability. The reservoir is characterized by stacked pay opportunities, which refers to the presence of multiple potential producing formations beneath a given surface location. We believe these opportunities allow for relatively low cost development and replacement of reserves, which supports us in prolonging the life of our producing fields. Historically, the Who Dat assets have exhibited predictable and reliable production which has been achieved through LLOG's in-field and near-field development program.

The below chart shows the overall gross historical production performance of the Who Dat assets by calendar year in MMboe.[33]

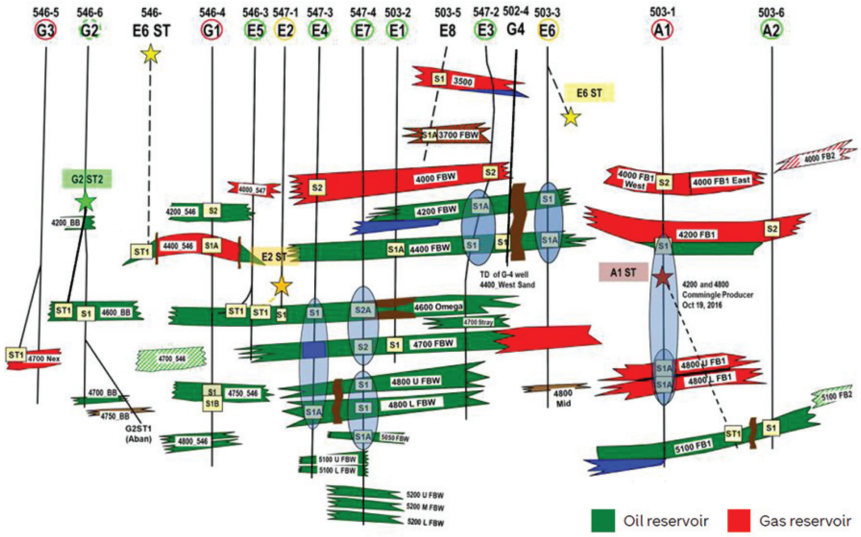
Who Dat Historical Production (MMboe)[34]



32 Wood Mackenzie Consulting, Karoon Energy, Brazil and US Gulf of Mexico Offshore Market Assessment, April 2024. See Annex B.
33 Source: Historical production data provided by LLOG.
34 Historical production shown on a gross basis.

Who Dat currently has 14 producing wells (and one non-producing well). A new well, a sidetrack and a subsea pump were brought online during the second half of 2023. Some wells are produced intermittently for reservoir management purposes or may be shut in from time to time for other reasons. These added approximately 10,000 boepd (gross) to overall production or 2,400 boepd to our share of production on a NRI basis. A sidetrack of one of the wells encountered a shallower reservoir as well as the original deeper target. As a result, completion plans were amended to enable production from either reservoir zone into the Who Dat floating production system facility. Subject to testing and determining optimal reservoir management strategies, we expect the shallow zone to provide incremental production and reserves. A new well and a sidetrack within the Who Dat field were brought online during February 2024. We estimate that this new well and sidetrack will lead to additional 6,000-8,000 boepd (gross), or 3,000 boepd of our share of production on a NRI basis.

The chart below shows the Who Dat reservoir unit cross section.



Production

The following table summarizes, on a NRI basis, our historical key operating and production metrics for our Who Dat assets for TY23 and *pro forma* operating and production metrics for FY23 and TY23 as if we had acquired our share in the Who Dat assets on July 1, 2022. See "Unaudited pro forma combined financial information" and "Selected unaudited pro forma combined financial information."

	Historical[(1)]	**Pro Forma**[(2)]	
	TY23	**FY23**	**TY23**
Oil production (MMbbl)	0.06	1.62	0.93
Gas production (MMboe)	0.03	1.12	0.52
NGL production (MMboe)	0.0	–	0.0
Total production (MMboe)	**0.09**	**2.74**	**1.45**
Unit production cost (US$/boe)[(3)]	7.09	10.42	11.80
Production facility uptime (%)[(4)]	96%	99%	96%

Notes:

(1) Includes our share in the Who Dat assets on a NRI basis for the period from December 21, 2023 to December 31, 2023, following our acquisition.

(2) Includes our share in the Who Dat assets on a NRI basis as if we had acquired our share in the Who Dat assets on July 1, 2022.

(3) Includes processing and transportation expenses.

(4) We calculate the floating production system uptime rate for Who Dat by dividing the number of days with production by the number of days in the given time period, excluding scheduled downtime.

The following table summarizes the overall gross historical performance of certain key operating and production metrics for our Who Dat assets for FY23, HY23 and TY23.

	FY23	HY23	TY23[(1)]
Oil production (MMbbl)	6.74	3.36	3.78
Gas production (Bcf)	29.53	15.97	13.96
NGL production (Mgal)	–	–	0.0
Total production (MMboe)	**11.66**	**6.02**	**6.10**
Production cost (US$/boe)[(2)]	10.42	10.26	11.80
Production facility uptime (%)	99%	99%	96%

Notes:

(1) We acquired the Who Dat assets on December 21, 2023.

(2) Production cost represents the direct operating expenses per boe. Includes processing and transportation expenses.

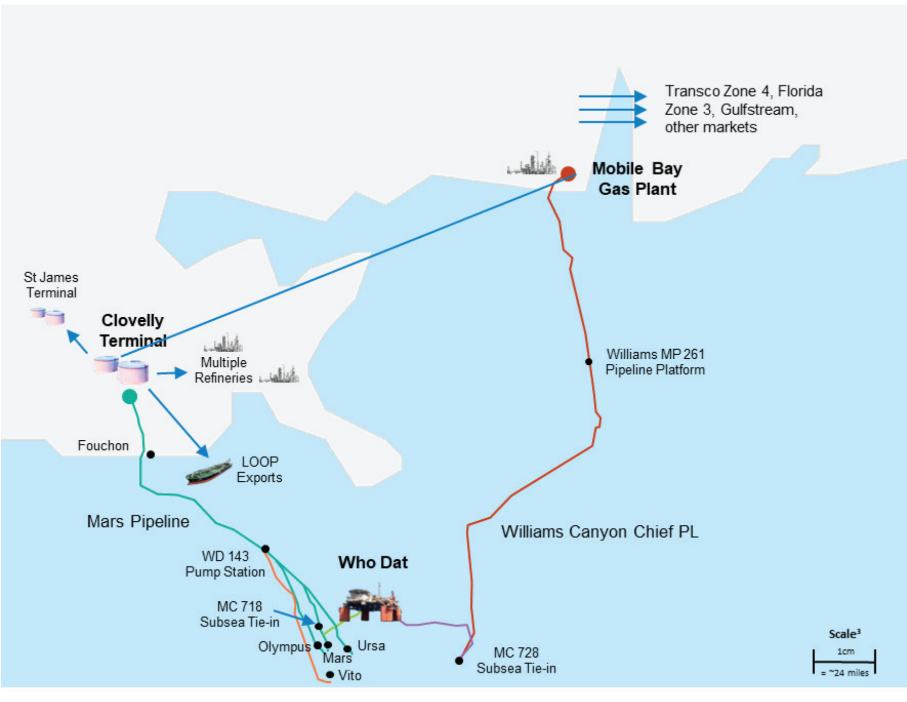
Products, sales and marketing

The oil and gas production from our Who Dat assets is processed through the Who Dat floating production system facility platform and then transported to our offtakers through common carrier pipelines.

Oil is transported via the Mars pipeline, a common carrier system operated by a subsidiary of Royal Dutch Shell Plc, through a Who Dat-owned lateral pipeline. The Mars pipeline has published rates to multiple terminals, refineries and the Louisiana offshore oil port for export. Oil from Who Dat is Mars grade and sold at a price equal to WTI crude oil as adjusted for the published Mars differential, a key reference price of crude oil within the US Gulf. This provides us with the ability to sell our production to multiple potential counterparties and refineries and diversify our offtakers, whilst optimizing our realized price.

Gas is transported through a Who Dat-owned lateral pipeline, into the Canyon Chief pipeline, an offshore gathering system operated by Williams and then delivered to the Transcontinental Gas pipeline. The Transcontinental Gas pipeline provides service to the Williams Mobile Bay gas plant, and then into multiple onshore markets. Who Dat gas is typically priced off Platt's Florida Zone 3 or Transco Zone 4 index, which are reference prices for gas in the Louisiana/Southeast region of the United States.

The chart below shows our pathway to market for Who Dat.



Following our acquisition until March 31, 2024, LLOG sold our share of the oil and gas produced from Who Dat on our behalf pursuant to a transitional services agreement.

Since April 1, 2024, we have sold our share of crude oil to BP Products North America Inc. under a month-to-month evergreen crude oil purchase agreement at a price equal to the forward price for the following month for WTI crude oil, adjusted for the published Mars differential, a monthly negotiated price differential, transportation costs and a quality adjustment reflecting the quality of the Who Dat crude oil compared to other crude oil transported on the Mars pipeline.

We sell our share of natural gas on a six-months seasonal contract basis to BP Energy Company under a gas purchase contract at a price equal to the Platt's Florida Zone 3 index, adjusted for a negotiated price differential and the cost of transportation and processing. This contract may be terminated by either party on providing 30 days of written notice.

We sell our share of natural gas liquids under a life-of-asset sales agreement to Williams Field Services, a U.S. based natural gas infrastructure provider, at prices linked to the Mont Belvieu index as adjusted for the cost of transportation and fractionation. This agreement terminates upon the permanent cessation of production from all dedicated leases. In addition, our joint venture is able to terminate the agreement if, among others, technical specifications in relation to the gas gathering system are not met.

We expect to finalize further offtake and marketing agreements through 2024, which would give us additional options to optimize sales. See also "Management's discussion and analysis of financial condition and results of operations – Overview – Key income statement line items – Revenue."

The following table summarizes, on a NRI basis, our historical key sales metrics for our Who Dat assets for TY23, and *pro forma* sales metrics for FY23 and TY23 as if we had acquired our share in the Who Dat assets on July 1, 2022. See "Unaudited pro forma combined financial information" and "Selected unaudited pro forma combined financial information."

	Historical[(1)]	**Pro Forma**[(2)]	
	TY23	**FY23**	**TY23**
Oil sales volume (MMbbl)	0.06	1.60	0.90
Gas sales volume (Bcf)	0.03	5.88	2.78
NGL sales volume (Mgal)	–[(3)]	5.15	2.46
Total Sales volume (MMboe)	**0.09**	**2.70**	**1.42**
Weighted average realized oil price (net of selling expenses) (US$/bbl)	70.59	80.08	81.77
Weighted average realized gas price (net of selling expenses) (US$/mcf)	2.78	5.84	3.17
Weighted average realized NGL price (net of selling expenses) (US$/gal)	–[(3)]	0.86	0.71
Weighted average realized price (US$/boe)	**42.22**	**61.73**	**59.19**

Notes:

(1) Includes our share in the Who Dat assets on a NRI basis for the period from December 21, 2023 to December 31, 2023, following our acquisition.

(2) Includes our share in the Who Dat assets on a NRI basis as if we had acquired our share in the Who Dat assets on July 1, 2022.

(3) We did not report any NGL sales volumes in TY23.

Licensing and royalties

The leases for our US Gulf of Mexico assets are standard U.S. federal offshore Outer Continental Shelf oil and gas leases awarded by the U.S. Bureau of Ocean Energy Management or BOEM. These leases are subject to regulation by, among others, the U.S. Bureau of Safety and Environmental Enforcement and the Office of Natural Resources Revenue. We pay royalties in the amount of 12.50% of the value of production to the Office of Natural Resources Revenue.[35] Under certain conditions, we are able to obtain royalty relief in the form of temporary waivers of royalty payments. Royalty relief may be available if market prices are low or if the US government wants to incentivize production in frontier areas or deeper depth.

We present the revenue we earn from our USA segment on a net of royalties basis. Because royalties can be taken in kind in the United States, our USA segment revenues are our actual sales less any royalties levied, resulting in lower sales volumes and revenue than if we reported on the same basis as our Brazilian segment. See "Management's discussion and analysis of financial condition and results of operations – Key factors affecting our results – Government royalties" and "Regulatory overview – Regulatory overview – US Gulf of Mexico."

In addition, we pay royalties in connection with specific leases to third parties under agreements with prior interest holders. For example, certain limited zones of block MC 502, on which the Who Dat field is partly located, are subject to a 5% overriding royalty stemming from a farm-out agreement with Eni Petroleum US LLC.

Who Dat reserves

The following tables set forth our NRI of 1P, 2P and 3P reserve estimates for the Who Dat assets as of December 31, 2023.

We engage independent experts as required to assist with the integrity of our reserves and contingent resources estimates. We engaged independent expert Netherland, Sewell & Associates, Inc., or NSAI, to deliver an independent reserve report for the Dome Patrol and Who Dat oil and gas fields, as of December 31, 2023. A summary of this report has been included in this offering memorandum in Annex A. We have relied upon NSAI's independent reserve report in preparing our estimates of our share of reserves and contingent resources from the Who Dat assets, and any differences between our estimates and the estimates presented by NSAI relate to differences in oil price forecasts. As of December 31, 2023, NSAI's estimate of our share of 2P reserves from the Who Dat assets was approximately 0.6% lower than our estimate of 2P reserves. We believe that the differences between our reserves estimates and those of NSAI reflect differences in reasonable professional judgment in interpreting data and applying assumptions and are not material. See "Cautionary note regarding reserves and contingent resources" and "Reserves and contingent resources."

35 Source: Wood Mackenzie Consulting, Karoon Energy, Brazil and US Gulf of Mexico Offshore Market Assessment, April 2024, Section 4.5 US GoM Fiscal Summary. See Annex B.

We have used a conversion factor of 6 mcf equaling 1 boe to convert from gas to oil equivalent. In accordance with the US Gulf of Mexico fiscal scheme, our NRI shows our working interest net of royalties charged by the American Office of Natural Resources Revenue and third-party royalties. See also "Cautionary note regarding reserves and contingent resources," "Reserves and contingent resources" and "– Licensing and royalties."

Reserves

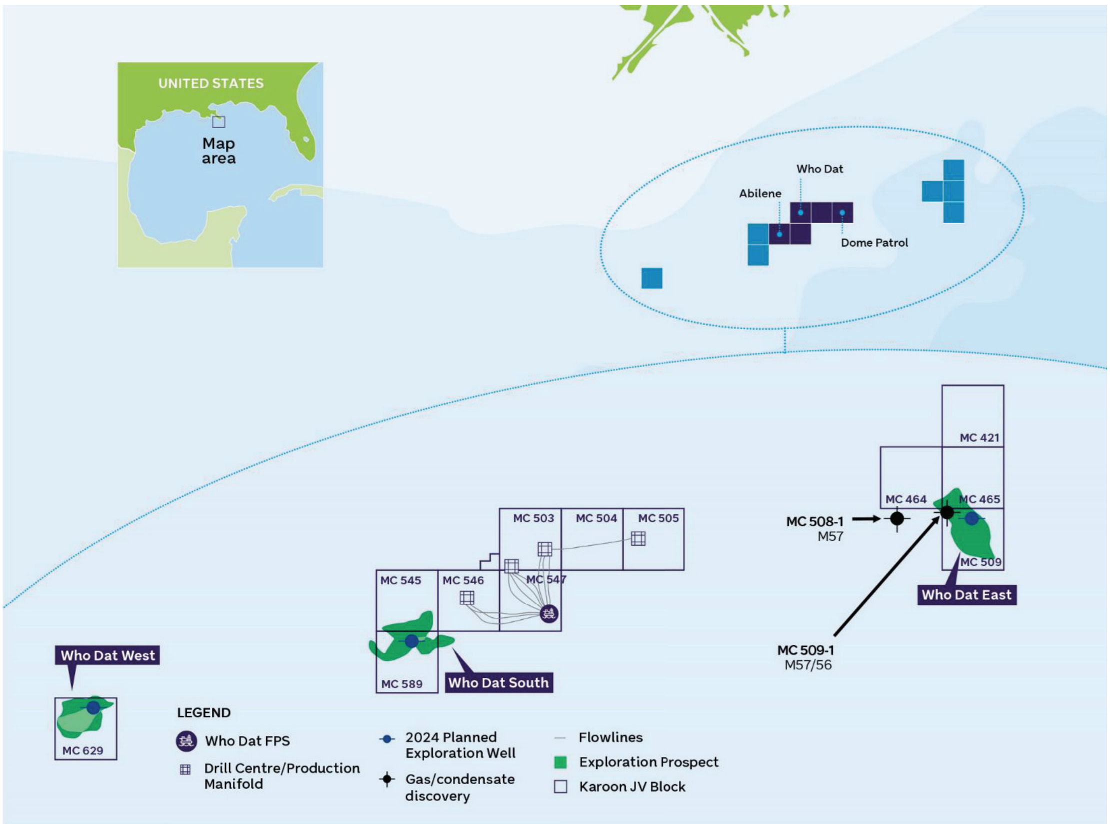
	As of December 31, 2023		
	1P	**2P**	**3P**
Who Dat, Dome Patrol and Abilene			
Oil (MMbbl)	13.9	19.5	29.1
Gas (bcf)	37.7	61.5	79.8
NGL (MMbbl)	0.7	1.2	1.5
Oil equivalent (MMboe)	**20.9**	**31.0**	**43.9**

Development and exploration assets

As part of our acquisition of the Who Dat assets, we also acquired varying interests in adjacent acreage including the Who Dat East (40% interest), Who Dat West (35% interest) and Who Dat South (30% interest) exploration and appraisal opportunities.

All three of the Who Dat East, Who Dat West, and Who Dat South opportunities are within tie-back distance of the Who Dat floating production system. We estimate that drilling costs for these prospects will be approximately US$60 million per well on a gross, dry-hole basis and that our share of capital costs for all three wells will amount to approximately US$100-120 million. As part of our acquisition, we agreed to up to US$39.2 million in additional payments relating to the exploration of Who Dat East and Who Dat West. All drilling opportunities in the Who Dat prospects are amplitude-supported and calibrated by nearby wells and proven reservoirs. This approach has led to high drilling success rates in the past.

The following map show the location of Who Dat West, Who Dat South and Who Dat East.



Who Dat East

Who Dat East lies 27 kilometers east of the Who Dat floating production system facility. The joint venture intends to drill an appraisal well at Who Dat East starting in late April 2024. We also expect an exploration well to be drilled at Who Dat South in the second half of 2024, and subject to approval by the joint venture partners, a second exploration well to be drilled at Who Dat West, also during the second half of 2024. All three of these opportunities are within tie-back distance of the Who Dat floating production system. We have estimated 2C contingent resources of 5.4 MMboe on a NRI basis for our share of Who Dat East. Within the Who Dat East permit, there is also a deeper Cretaceous gas target for which seismic studies are ongoing.

The following tables sets forth our NRI of our 2C contingent resource estimates for Who Dat East as of December 31, 2023. See also "Cautionary note regarding reserves and contingent resources" and "Reserves and contingent resources."

Contingent resources

	As of December 31, 2023
	2C
Who Dat East	
Oil (MMbbl)	1.9
Gas (bcf)	20.5
NGL (MMbbl)	0.0
Oil equivalent (MMboe)	**5.4**

Who Dat West

Who Dat South lies 31 kilometers west of the Who Dat field. Subject to joint venture approvals, we expect an exploration well to be drilled at Who Dat West in the second half of 2024, which will target multiple Middle Miocene stacked reservoirs.

Who Dat South

Who Dat South lies 11 kilometers south-west of the Who Dat field. Subject to joint venture approvals, we expect an exploration well to be drilled at Who Dat South in the second half of 2024.

Joint venture partners

Our joint venture partners for the Who Dat and Dome Patrol oil and gas fields are LLOG (45%) and Westlawn (25%). Our joint venture partners for the Abilene field are LLOG (approximately 21%), Westlawn (approximately 12%) and China National Offshore Oil Corporation (approximately 50%). All of our Who Dat assets are operated by LLOG, a private independent US operator with extensive technical expertise and experience.

We have entered into several conventional US Gulf of Mexico deepwater joint operating agreements with our joint venture partners in connection with our Who Dat assets. These operating agreements contain usual terms and conditions relating to the commitment of expenditure and the undertaking of joint operations by the operator on behalf of joint venture participants. Usual terms regarding the election to participate in certain joint operations such as exploration or development are included, generally with the ability for specific joint venture participants being afforded the opportunity to opt out of certain operations or developments at certain times. Each joint venture participant is entitled to receive and market its share of production.

Production and sales summary

The following tables summarize our historical production and sales data for FY21, FY22, FY23, HY23 and TY23, and *pro forma* production and sales data on a net revenue interest basis for FY23 and TY23 as if we had acquired our share in the Who Dat assets on July 1, 2022. See "Unaudited pro forma combined financial information" and "Selected unaudited pro forma combined financial information."

	Historical					Pro Forma[2]	
	For the six months ended December 31,		For the twelve months ended June 30,			For the twelve months ended June 30,	For the six months ended December 31,
	2022	2023[1]	2021	2022	2023	2023	2023
Production (MMboe)	3.37	5.47	3.14	4.64	7.04	9.78	6.83
Sales volume (MMboe)	3.41	5.07	2.90	4.54	7.06	9.76	6.40
Weighted average realized price (net of selling expense) (US$/boe)	87.86	81.51	59.00	84.74	80.20	75.09	77.11

Notes:

(1) Includes our share in the Who Dat assets on a NRI basis for the period from December 21, 2023 to December 31, 2023, following our acquisition.

(2) Includes our share in the Who Dat assets on a NRI basis as if we had acquired our share in the Who Dat assets on July 1, 2022.

The following tables summarize our historical production volumes by asset and by product for FY21, FY22, FY23, HY23 and TY23.

Production volume by assets

	For the six months ended December 31,		For the twelve months ended June 30,		
	2022	2023	2021	2022	2023
Brazil					
Baúna (MMbbl)	3.37	5.38	3.14	4.64	7.04
United States					
Who Dat[1] (MMboe)	–	0.09	–	–	–
Total (MMboe)	**3.37**	**5.47**	**3.14**	**4.64**	**7.04**

Note:

(1) Includes our share in the Who Dat assets on a NRI basis for the period from December 21, 2023 to December 31, 2023, following our acquisition.

Production volume by product

	For the six months ended December 31,		For the twelve months ended June 30,		
	2022	2023[1]	2021	2022	2023
Oil (MMbbl)	3.37	5.44	3.14	4.64	7.04
Gas (MMboe)	–	0.03	–	–	–
Total (MMboe)	**3.37**	**5.47**	**3.14**	**4.64**	**7.04**

Note:

(1) Includes our share in the Who Dat assets on a NRI basis for the period from December 21, 2023 to December 31, 2023, following our acquisition.

The following tables summarize our sales volume by asset and by product for FY21, FY22, FY23, HY23 and TY23.

Sales volume by asset

	For the six months ended December 31,		For the twelve months ended June 30,		
	2022	2023	2021	2022	2023
Brazil					
Baúna (MMbbl)	3.41	4.98	2.90	4.54	7.06
United States					
Who Dat[1] (MMboe)	–	0.09	–	–	–
Total (MMboe)	**3.41**	**5.07**	**2.90**	**4.54**	**7.06**

Note:

(1) Includes our share in the Who Dat assets on a NRI basis for the period from December 21, 2023 to December 31, 2023, following our acquisition.

Sales volume by product

	For the six months ended December 31,		For the twelve months ended June 30,		
	2022	2023[1]	2021	2022	2023
Oil (MMbbl)	3.41	5.04	2.90	4.54	7.06
Gas (MMboe)	–	0.03	–	–	–
Total (MMboe)	**3.41**	**5.07**	**2.90**	**4.54**	**7.06**

Note:

(1) Includes our share in the Who Dat assets on a NRI basis for the period from December 21, 2023 to December 31, 2023, following our acquisition.

Reserves and contingent resources

The following table summarizes our net oil and gas 1P, 2P and 3P reserves estimates as of December 31, 2023. For more information on our reserves and resources, see "Cautionary note regarding reserves and contingent resources" and "Reserves and contingent resources."

	As of December 31, 2023[1]		
	1P	2P	3P
		(MMboe)	
Brazil			
Baúna[2]	37.1	46.5	55.8
United States			
Who Dat[3]	20.9	31.0	43.9
Total	**58.0**	**77.5**	**99.7**

Notes:

(1) We engaged independent experts AGR Energy Services AS, or AGR, and Netherland, Sewell & Associates, Inc., or NSAI, to deliver independent reserve reports for Baúna and for the Dome Patrol and Who Dat oil and gas fields, respectively, as of December 31, 2023. Summaries of those reports have been included in this offering memorandum in Annex A. As of December 31, 2023, AGR's estimate of our 2P reserves in Baúna was approximately 2.5% lower than our estimate of 2P reserves. We have relied upon NSAI's independent reserve report in preparing our estimates of our share of reserves and contingent resources from the Who Dat assets, and any differences between our estimates and the estimates presented by NSAI relate to differences in oil price forecasts. As of December 31, 2023, NSAI's estimate of our share of 2P reserves from the Who Dat assets was approximately 0.6% lower than our estimate of 2P reserves. We believe that the differences between our reserves estimates and those of AGR and NSAI reflect differences in reasonable professional judgment in interpreting data and applying assumptions and are not material. See "Cautionary note regarding reserves and contingent resources" and "Reserves and contingent resources."

(2) Includes developed reserves from the producing Baúna, Piracaba and Patola oil fields. We had no undeveloped 1P, 2P or 3P reserves as of December 31, 2023 in Baúna.

(3) Includes our share of developed and undeveloped reserves from the producing Who Dat, Dome Patrol and Abilene oil and gas fields.

The following tables summarize our net oil and gas 2C contingent resources estimates as of December 31, 2023. For more information on our reserves and resources, see "Cautionary note regarding reserves and contingent resources" and "Reserves and contingent resources."

	As of December 31, 2023
	2C
	(MMboe)
Brazil	
Baúna[1]	10.9
Neon	60.1
Goia	27.0
United States	
Who Dat East[2]	5.4
Total (MMboe)	**103.4**

Notes:

(1) Includes Contingent Resources from the Baúna, Piracaba and Patola oil fields.

(2) Includes our share of Contingent Resources in the Who Dat East oil and gas field on a NRI basis.

Our concession agreements and leases

The table below shows our interests in petroleum tenements as of the date of this offering memorandum.

Field	Exploration permit/block	Operator	Interest held	Concession term/status	Termination events
Santos Basin, Brazil					
Baúna	Concession BM-S-40	Karoon	100%	Exploration and production rights granted until 2039.	All our concession agreements in Brazil are subject to termination by ANP under certain circumstances. See "– Termination events of our concession agreements in Brazil" below.
Neon	Block S-M-1037	Karoon	100%	Exploration and production rights granted until 2045.	
Goiá.............	Block S-M-1101	Karoon	100%	Exploration and production rights granted until 2045.	
Clorita	Block S-M-1537	Karoon	100%	Exploration rights granted until 2025.(1)	
Block S-M-1356	Block S-M-1356	Karoon	100%	We successfully participated in government bid round in December 2023 and expect the concession contract to be signed within the second quarter of 2024.(2)	
Block S-M-1482	Block S-M-1482	Karoon	100%	We successfully participated in government bid round in December 2023 and expect the concession contract to be signed within the second quarter of 2024.(2)	

Field	Exploration permit/block	Operator	Interest held	Concession term/status	Termination events
Mississippi Canyon, Gulf of Mexico, United States					
Who Dat.......	MC 502	LLOG	30%	Held by production Certain limited zones subject to a 5% overriding royalty interest by Eni Petroleum US LLC	All leases in the Gulf of Mexico are subject to termination by BOEM (i) if the holder of interest fails to comply with any provision of the OCSLA, the lease, or applicable regulations; (ii) if BOEM determines the lease was obtained by fraud or misrepresentation; (iii) if after a hearing, it is determined continued activity will probably cause serious harm or damage to life, property, any mineral, national security or defense, or the marine, coastal, or human environment; (iv) any time after lease operations have been suspended or temporarily prohibited by the Department of Interior continuously for a period of 5 years; or (v) if the holder of an interest in a lease fails to provide a bond, or alternative type of security instrument acceptable to BOEM. Any lease will also terminate automatically pursuant to the terms of the lease if there is no production, drilling or other qualifying operations being conducted.
	MC 503			Held by production Subject to overriding royalty interests by several third parties, including Black Streak in the amount of 0.6%	
	MC W/2 504			Subject to expiration by June 30, 2024 unless drilling operations or production in paying quantities commences. The joint venture currently has no plans to drill or apply for unitization of this field.	
	MC E/2 546			Held by production	
	MC E/2 547			Held by production	
Dome Patrol .	MC E/2 504	LLOG	30%	Subject to expiration by June 30, 2024 unless drilling operations or production in paying quantities commences. The joint venture currently has no plans to drill or apply for unitization of this field.	
	MC E/2 505			Held by production	
Abilene.........	MC W/2 546	LLOG		Held by production	
Who Dat South............	MC 545	LLOG	30%	Subject to expiration by September 30, 2024 unless drilling operations or production in paying quantities commences.	

Field	Exploration permit/block	Operator	Interest held	Concession term/status	Termination events
	MC 589			Subject to expiration by July 31, 2024 unless drilling operations or production in paying quantities commences.	
Who Dat West..........	MC 629	LLOG	35%	Subject to expiration by June 30, 2024 unless drilling operations or production in paying quantities commences.	
Who Dat East...........	MC 509	LLOG	40%	Subject to expiration by June 30, 2025 unless drilling operations or production in paying quantities commences. LLOG has applied for unitization of the Who Dat East field.(3) Following a successful unitization application, our joint venture application intends to drill an exploration well on MC 509, which will satisfy the requirements to extend the leases of the unitized Who Dat East field.	
	MC 421			Subject to expiration by May 31, 2024 unless drilling operations or production in paying quantities commences. Subject to a 2% overriding royalty interest by Hess Corporation LLOG has applied for unitization of the Who Dat East field.(3)	
	MC 464			Subject to expiration by May 31, 2024 unless drilling operations or production in paying quantities commences. Subject to a 2% overriding royalty interest by Hess Corporation LLOG has applied for unitization of the Who Dat East field.(3)	

Field	Exploration permit/block	Operator	Interest held	Concession term/status	Termination events
	MC 465			Subject to expiration by May 31, 2024 unless drilling operations or production in paying quantities commences. Subject to a 2% overriding royalty interest by Hess Corporation LLOG has applied for unitization of the Who Dat East field.(3)	
	MC 508			LLOG has negotiated a lease exchange agreement with Chevron, leaseholder of MC 508, under which Chevron would transfer lease MC 508 to LLOG, which will then transfer the relevant interests to the joint venture partners. In consideration for the transfer Chevron would be granted exploration and production rights below 27,600ft in MC 508, MC 421 and MC 464. The agreement remains subject to approval, including from the joint venture partners. LLOG has applied for unitization of the Who Dat East field, including MC 508.(3)	

Notes:

(1) By January 2025, we can either (i) request an extension of the exploration phase, (ii) return the block to ANP or (iii) declare the commerciality of the block and enter in the development phase.

(2) We expect to be granted seven years of exploration rights after which we can either (i) request an extension of the exploration phase, (ii) return the block to ANP or (iii) declare the commerciality of the block and enter in the development phase.

(3) Unitization is a process by which leases or parts thereof, are combined and operated as a single unit, with production or operations from one tract in the unit being treated as production or operations from every tract included in the unit.

Termination events of our concession agreements in Brazil

The following table sets out the circumstances our concession contracts can be terminated for each field in Brazil.

Field	Termination events
Baúna.......................	Our concession contract may be terminated: (i) in case of non-compliance with any of our obligations which is not corrected within 90 days of notice; (ii) if we are declared bankrupt, insolvent or file for bankruptcy; (iii) if by the end of the exploration term there is no discovery in the concession area; (iv) in the case of a severe unforeseeable event or force majeure; or (v) by us at any time during the production phase by means of a written notification to ANP.
Neon and Goiá..........	Our concession contract may be terminated: (i) in case of non-compliance with any of our obligations which is not corrected within 90 days of notice; (ii) if we are declared bankrupt, insolvent or file for bankruptcy; (iii) if by the end of the exploration term there is no discovery in the concession area; (iv) in the case of a severe unforeseeable event or force majeure; or (v) by us at any time during the production phase by means of a written notification to ANP; (vi) if the proposed licensing necessary for exploration activities receives a definitive rejection from the competent environmental agencies; or (vii) in case of failure to execute any required production individualization agreement.
Clorita......................	Our concession contract may be terminated: (i) upon expiry of its term; (ii) if we have not complied with the minimum exploration program at the end of the exploration phase; (iii) if no commercial discovery was made at the end of the exploration phase; (iv) if we return the concession area in its entirety; (v) if a development plan has not been submitted within a deadline specified by ANP; (vi) if ANP fails to approve the development plan; (vii) in case of a refusal to sign the production individualization agreement in whole or in part, following a decision by ANP; (viii) in the case of a decree of bankruptcy or failure by the competent court to approve our application for judicial reorganization; (ix) by mutual agreement between the parties at any time, without prejudice to the fulfilment of the obligations in the concession contract; (x) during the production phase, by us through providing notice to ANP at least 180 days prior to the intended date of termination; (xi) in case of non-compliance with any of our obligations which is not corrected within 90 days of notice; (xii) in case of a judicial or extrajudicial reorganization, unless we have submitted an approved reorganization plan which demonstrates to ANP the economic and financial capacity to fully comply with all our contractual and regulatory obligations; (xiii) in the case of a severe unforeseeable event or force majeure; (xiv) if the proposed licensing necessary for exploration activities receives a definitive rejection from the competent environmental agencies; or (xv) if the concession contract is suspended for licensing purposes for a term greater than 5 years.

Field	Termination events
Block S-M-1356 and Block S-M-1482.....	Our concession contract may be terminated: (i) upon expiry of its term; (ii) if we have not complied with the minimum exploration program at the end of the exploration phase; (iii) if no commercial discovery was made at the end of the exploration phase; (iv) if we return the concession area in its entirety; (v) if we exercise our right to withdraw during the exploration phase, provided that we have complied with the minimum exploration program or have paid a corresponding compensation amount; (vi) if a development plan has not been submitted within a deadline specified by ANP; (vii) if ANP fails to approve the development plan; (viii) in case of a refusal to sign the production individualization agreement in whole or in part, following a decision by ANP; (ix) in case of failure to renew financial guarantees within 30 days prior to their expiration date; (x) in the case of a decree of bankruptcy or failure by the competent court to approve our application for judicial reorganization; (xi) by mutual agreement between the parties at any time, without prejudice to the fulfilment of the obligations in the concession contract; (xii) during the production phase, by us through providing notice to ANP at least 180 days prior to the intended date of termination; (xiii) in case of non-compliance with any of our obligations which is not corrected within 90 days of notice; (xiv) in case of a judicial or extrajudicial reorganization, unless we have submitted an approved reorganization plan which demonstrates to ANP the economic and financial capacity to fully comply with all contractual and regulatory obligations; (xv) in case of a partial termination of the concession contract in case we do not provide adequate financial guarantees for the minimum exploratory program, provided that the respective areas are not in development; (xvi) in the case of a severe unforeseeable event or force majeure; (xvii) if the proposed licensing necessary for exploration activities receives a definitive rejection from the competent environmental agencies; or (xviii) if the concession contract is suspended for licensing purposes for a term greater than 5 years.

Sustainability

Sustainability is a core element of our business strategy and underpins our vision to deliver energy through safe, reliable and responsible operations. We link our executive remuneration to specific outcomes within the health, safety and security and climate pillars, reflecting our core ESG priorities.

Climate

While we continue to grow as a producer and build on our existing operations, we are aiming to optimize our processes so that our emissions are, wherever practical, reduced in terms of emissions intensity. Our carbon management action plan, which we first adopted in 2021, is designed to deliver short term and longer-term climate-related outcomes. For the Baúna Project, we have a continued objective of being carbon neutral and a target to be net zero (Scope 1 and 2) by 2035.

CARBON NEUTRAL FY 2023 SCOPE 1 AND 2 GHG EMISSIONS		
Baúna Project Expected to remain Carbon Neutral*	Carbon Neutral on new assets within five years of purchase*	Internal carbon pricing for new investment decisions
NET ZERO BY 2035 SCOPE 1 AND 2 GHG EMISSIONS		

* Scope 1 and 2 GHG emissions

We report our sustainability metrics with reference to the voluntary 'IFRS Sustainability Disclosure Standards', developed by the International Sustainability Standards Board and are also guided by the Australian National Greenhouse and Energy Reporting Act for our carbon accounting.

Our carbon management action plan

Our carbon management action plan describes how we want to achieve our targets:

- *Avoid and reduce:* We were able to avoid emissions of 2,850tCO_2e in FY22 and 5,293tCO_2e in FY23 through operational improvements including the installation of a mooring buoy in FY22 and optimizing support vessel scheduling. As part of our emissions reduction program for 2024, we are undertaking a review of the energy generation systems at Baúna.

- *Assess investments in high quality offsets:* We have a 9-year agreement in place with SWST to purchase over 480,000 externally verified emission reduction certificates, which we expect will offset approximately 60% or our forecast Baúna emissions. During TY23, we signed an exclusive 5-year agreement with Carbonext, securing over 340,000 externally verified carbon units with an additional certification under the 'Climate, Community and Biodiversity Standards.' These relate to the 'Hiwi REDD+' project, located in Bujari, Northern Brazil and are registered with global certifier of voluntary carbon offsets VERRA.

- *Purchase of additional offsets if required:* We continue to investigate opportunities to acquire high quality carbon offsets as we work towards developing our own carbon projects. Until we acquire a portfolio of offset generating assets we will need to rely on offset purchases from external providers.

- *Internal carbon pricing:* We are applying an internal carbon price ranging from approximately US$45/t in 2023 to more than US$130/t in 2050 to take emissions into account in our internal decision making whenever we consider new investments. We also include actual abatement costs of projects in our budgets to assist with the purchase of appropriate amounts of carbon credits.

Our climate performance

Scope 1 emissions are direct emissions from sources that we own or control. This includes emissions from stationary combustion (for example in generator turbines onboard the floating production, storage and offloading facility), mobile combustion (for example in supply vessels and fleet cars), fugitive emissions (for example from general leaks) and process emissions (for example from flaring).

Scope 2 emissions are indirect emissions from the generation of purchased energy in our operations. Scope 2 emissions account for less than 0.1% of our total Scope 1 and 2 emissions. Our Australian office participates in the Australian GreenPower program since 2021, ensuring that our electricity use is matched with power from renewable electricity sources such as solar, wind and biomass.

The following tables show our historical Scope 1 and Scope 2 emissions data for TY23, FY23 and FY22.

	TY23	FY23	FY22
Scope 1 emissions (tCO_2e)	**59,319**	**142,025**	**82,805**
Operational control(1)	58,866	142,025	82,805
Equity share(2)	453	–	–
Scope 2 emissions (tCO_2e)	**28**	**49**	**65**
Operational control(1)	28	49	65
Equity share(2)	–	–	–
Scope 1 and 2 emissions (tCO_2e)	**59,347**	**142,074**	**82,870**
Operational control(1)	58,894	142,074	82,870
Equity share(2)	453	–	–
Emissions Intensity ($KgCO_2e/bbl$)	10.9	20.2	17.9

Notes:

(1) This data includes emissions relating to the Baúna asset and other operations under our control.

(2) This data includes emissions relating to our equity share in our US Gulf of Mexico assets following our acquisition on December 22, 2023. It does not include drilling.

The Baúna workover program, the Patola development, and drilling of two control wells at the Neon oil field significantly increased our GHG emissions during FY23. The rig operations also more than doubled our production rates prior to commencing natural decline, which reduced our Scope 1 and 2 emissions intensity. Our annualized GHG emissions decreased slightly during TY23, partially due to the completion of drilling operations in the previous period.

Our Scope 1 and Scope 2 emissions intensity was above 20.0 $kgCO_2e/bbl$ during the year ended December 31, 2023 due to drill and construction activities. Due to operational efficiencies and increased production volumes, our Scope 1 and Scope 2 emissions intensity dropped to 10.9 $kgCO_2e/bbl$ during TY23. Our emissions are reported in terms of tonnes carbon dioxide equivalent and primarily comprise carbon dioxide, methane and nitrous oxide.

Approximately 40% of the associated gas produced at the Baúna floating production, storage and offloading facility is used to power the floating production, storage and offloading facility with most of the remainder reinjected and only a small amount flared for process safety. Recognizing the damaging effects of methane, we aim to minimize flaring in our operations.

Our emissions outlook

Following the workover and drilling campaign, oil production at the Baúna project increased materially. It has now resumed a gradual decline, consistent with reservoir models. This is expected to increase the Company’s emissions intensity over the next year. In addition, the acquisition of our US Gulf of Mexico assets during TY23 has increased our scale and diversification and will also increase our absolute GHG emissions portfolio. We continue to progress studies and projects to reduce our emissions intensity and the absolute emissions of our respective operations and implement these, where practical.

Environment

We are committed to conducting safe, reliable, and responsible operations while minimizing our environmental impact and protecting biodiversity. We are continuously monitoring a range of parameters to ensure compliance with applicable environmental regulations and license requirements. Our key monitoring areas are water and plankton; sediment and benthic habitat; produced water, and oil spills.

Our oil spill response plan encompasses a systematic approach that includes preventive measures, preparedness, and response actions, such as regular maintenance of equipment, safety protocols, and training programs for crew members. We conduct regular drills and maintain the availability of support vessels on standby during operations. Consistent with industry practice, we enter into clubbing arrangements with other industry participants to assist in oil spill response. Additionally, we established a standing agreement with a well control services company to address major incidents efficiently.

We employ the 'Spilltrack System' to monitor and forecast oil drift at sea. Leveraging the Spilltrack System emergency response buoys, ocean drifters, and 'Expendable Current Profiler' probes, we have access to oil dispersion modelling, trajectory monitoring of oil slicks on the ocean surface, and current measurements along the water column. These advanced tools provided integrated support to response vessels, enabling the best estimation of oil slick directions and optimizing our response efforts to reduce environmental impacts.

We are also subject to decommissioning requirements in connection with our operations. For example, we are required to provide assurance of and a detailed decommissioning plan five years prior to the planned end of our production at Baúna.

The table below shows our environmental incidents for TY23, HY23, FY23, FY22 and FY21, including incidents related to contractors undertaking work for us. It does not include data from our partly-owned and non-operated assets in the US Gulf of Mexico, which we acquired during TY23.

	HY23	**TY23[1]**	**FY21**	**FY22**	**FY23**
Number of minor spills (to sea)[2]	0	1	2	0	2
Number of non-minor spills	0	0	0	0	0
Number of incidents in offloading operations	0	0	0	0	0

Notes:

(1) This data does not include incidents for our US Gulf of Mexico assets, which we acquired on December 22, 2023.

(2) Minor spills are spills having a volume of less than 0.16 m^3 as defined by ANP.

Supply chain

We engage major suppliers through long-term charter and services contracts to undertake our Baúna production operations, and on short term contracts when undertaking other major activities. We conduct specific risk assessments ahead of operational activities and major investment decisions. We are working closely with our major suppliers, aiming to ensure worker health and safety is given first priority in relation to our operations. Our personnel also visit manufacturing facilities to inspect the working conditions and practices and we maintain ongoing engagement with our major suppliers.

We have distributed questionnaires to all our major suppliers globally to identify vulnerabilities to modern slavery risks in our supply chain entities since 2021. During TY23, we completed a modern slavery risk assessment for suppliers representing 99.5% of our annual spend during FY23. None of them were identified as high-risk. We have submitted our third Modern Slavery Statement in February 2024 in accordance with the obligations under the Australian Modern Slavery Act 2018 and also undertake screening in relation to anti-bribery, fraud and corruption and health, safety, security and environmental matters.

Community engagement

In connection with our Baúna concession agreements, we have mandatory commitments to undertake projects to protect biodiversity and ecologically sensitive areas associated with our operational activities and to support community social initiatives.

Examples of our mandatory projects are the Social Communication Project and Project RUMO, which were both required by federal licensing overseen by the Brazilian Institute of Environmental and Renewable Natural Resources or IBAMA. The Social Communication Project consists of an ongoing information and consultation campaign that helps keep our staff, contractors, local communities, and regulatory authorities informed about our operations. Project RUMO was an environmental education project where we developed information about the use of the maritime zone and the coastal space of the Itajaí-Açu river estuary between November 2020 and February 2023.

We began to develop our voluntary investment program in Brazil during FY22 and have aligned our approach to the UN Sustainable Development Goals 4, 8 and 17, which focus on education and employment. Our projects during the year ended December 31, 2023 included support of 'Pro-Crep', a project that provides work opportunities and steady income to families in socially vulnerable situations and 'Liter of Light', a project with the objective of providing street lightning for the Alto da Serra Cafundá Quilombola Community, located in the city of Rio Claro-RJ.

Employees and industrial relations

We employed 115 full time and part-time employees as of December 31, 2023. In addition, on average, there were 83 employees of our contractor Altera & Ocyan working on the floating production, storage and offloading facility during FY23. The table below outlines where our employees are based as of December 31, 2023.

	Location		
	Australia	**Brazil**	**United States**
Office	27	86	2
Operational sites(1)	0	2	0

Note:

(1) Includes our personnel on board of the floating production, storage and offloading facility.

Industrial relations

We employ the vast majority of our employee workforce under individual common law contracts between the company and the employee. We believe we have experienced a harmonious and productive relationship with our employees with no significant industrial action or stoppages occurring across any projects over the past five years. As of the date of this offering memorandum, none of our employee workforce are members of any labor unions.

All suppliers and employees have access to grievance mechanisms through a whistleblower reporting service that facilitates both named and anonymous reporting. Employees and stakeholders can raise concerns confidentially via phone or email to our external reporting services (available in Portuguese and English), who will then pass the details of the report to our general counsel and chairman of the audit and risk committee.

Diversity

As of December 31, 2023, we had 115 permanent employees, of which 42% were women, exceeding our target of 30%. At the same date, 17% of our senior leaders, which we define as the three reporting levels below our chief executive officer, were women. Our participation rate of women on the board currently stands at 17%.

The following table shows the historical and target percentage of female participation across our business.

	As of December 31,			As of June 30,		
	2022	**2023**	**2025[1]**	**2021**	**2022**	**2023**
Board	17	17	30	17	17	14
Senior leadership[2]	17	17	30	26	17	11
Group	43	42	30	50	46	41

Notes:

(1) Target.

(2) The term “senior leadership” is defined for the purposes of the diversity analysis by reference to our internal organizational structure and encompasses the three reporting levels below our chief executive officer.

Health and safety

We prioritize the health and safety of our employees. The following table shows our safety performance for our operations, covering all personnel working on our operations, for FY21, FY22, FY23, HY23 and TY23. It does not include data from our partly-owned and non-operated assets in the US Gulf of Mexico, which we acquired during TY23.

Safety Performance[1]	**FY21**	**FY22**	**FY23**	**HY23**	**TY23**
Fatalities	0	0	0	0	0
High potential incidents[2]	1	2	1	0	0
Lost time injuries[3]	1	4	1	1	0
Medical treatment cases[4]	2	0	2	2	0
Restricted work cases[5]	1	0	1	1	0
Work exposure hours[6]	625,9281	1,028,000	1,948,000	1,026,000	468,664
Total recordable injury rate (per 200,000 hours)[7]	0.64	0.77	0.41	n/a	0.0
Lost time injury rate[8]	0.32	0.77	0.10	n/a	0.0
Tier 1 or 2 process safety events[9]	n/a	0	0	0	0

Notes:

(1) This table does not include data from our partly-owned and non-operated assets in the US Gulf of Mexico, which we acquired during TY23.

(2) High potential incidents are defined as any incident or near miss incident that could, in other circumstances, have realistically resulted in one or more fatalities.

(3) A lost-time injury is a work-related injury or illness that results in a person's disability, or time lost from work of one shift or more.

(4) Medical treatment cases are defined as cases that are not severe enough to be reported as lost work day cases or restricted work day cases but are more severe than requiring simple first aid treatment.

(5) Restricted work cases are defined as any work-related injury other than a fatality or lost work day case which results in a person being unfit for full performance of the regular job on any day after the occupational injury.

(6) Work exposure hours are total standard or actual hours worked by all employees and contractors during a specific period.

(7) A statistical measure of health and safety performance, calculated by the number of recordable incidents per 200,000 hours worked.

(8) A statistical measure of health and safety performance, calculated by the number of lost time injuries per 200,000 hours worked.

(9) Tier 1 and Tier 2 Process safety events are defined by API RP754, American Petroleum Institute Guide to Reporting Process Safety Events and refer to varying degrees of an unplanned or uncontrolled release of any material, including non-toxic and non-flammable materials (e.g. steam, hot water, nitrogen, compressed CO_2, or compressed air).

During FY23, we experienced a material increase in exposure hours due to the implementation of the Baúna Project workover campaign, the Patola development drilling and control well drilling at Neon. Despite increased exposure hours, we only experienced a total of four reportable safety incidents and injuries during FY23. The most significant of these was a lost time injury incident, constituting of a finger injury which required surgery. The worker subsequently returned to his duties without permanent injury.

Our US Gulf of Mexico assets are operated by our joint venture partner LLOG. According to data published by the Bureau of Safety and Environmental Enforcement in the United States, measured by total recordable injury rate per 200,000 hours, LLOG has historically had an above-industry safety record for the Who Dat assets. During the year ended December 31, 2023, the total recordable injury rate (per 200,000 hours) for the Who Dat assets stood at 0.0. At the end of March 2024, the Who Dat floating production system facility went through more than 4,550 days since its last reportable safety incident and more than 4,250 days since its last recordable safety incident.

Since taking operatorship of the producing Baúna oil field in November 2020, we have been working closely with the Baúna floating production, storage and offloading facility operator, Altera & Ocyan, to ensure our commitment to health, safety and environment is imbedded throughout the Baúna operations. This includes linking remuneration to safety performance.

Our operating management system encompasses policies, guidelines, and procedures and is regularly reviewed and updated. We also work with regulatory agencies such as the ANP and the Brazilian Institute of Environment and Renewable Natural Resources to conduct external audits, assessing our compliance with specific regulatory criteria.

We conduct hazard and operability studies at the activity level and risk assessments at the project and business levels. Our assessments are regularly updated, placing a strong emphasis on safety. We do not proceed with any activity until safety risks are reduced to as low as reasonably practicable and an acceptable level. We encourage our employees and contractors to halt work in unsafe situations or when relevant health, safety, or environmental controls are inadequate. We employ hazard reporting via our own and contractors' 'Safe Card' systems. Our crisis management team, based at our head office in Melbourne, Australia, maintains oversight of incident responses, and takes responsibility for controlling group-wide business continuity and strategic decision-making. Regular training drills are in place so that personnel are well prepared for emergency events, with IBAMA observing these drills at least once a year in Brazil. Key operational responses, including offshore medical evacuation and oil spill response, are thoroughly tested through full deployment drills. We monitor the Baúna facility's safety performance via regular reporting and audits, and our onboard company representatives.

We also place a heavy emphasis on safety standards as part of our contracting process and review the safety performance of our contractors. We will only contract with parties that have sufficient safety standards integrated into their operating practices.

Information Technology

As an oil and gas producer and operator of critical infrastructure, we aim to take a proactive approach to cyber risk management. We conduct regular risk assessments, vulnerability testing, and incident response planning and strive to identify and mitigate potential threats before cyber risks materialize. We employ a global infrastructure architecture in our operations to ensure group wide visibility of our operations and consistent event monitoring. Our cyber security framework complies with the American National Institute of Standards and Technology maturity level 3 as well as with the Australian Privacy Act and relevant Brazilian laws.

We employ a "one Karoon" strategy, providing a single controlled environment across a global domain program that spans our operations in Australia, Brazil and the United States. Our IT architecture provides a secure environment for business applications across our business and our layered approach allows, where required, for local area network infrastructure applications to run locally, within the protection of the group-wide network.

We also employ IT systems and security tools to increase our productivity and efficiency as well as reduce our vulnerability. For example, Altera & Ocyan use "SpillTrack System" on board of the *Cidade de Itajaí*. SpillTrack is a web-based tool to help us monitor and forecast oil drift at sea, which assists us in modelling of oil dispersion, monitoring of oil slicks and water current measurements. See "– Environment" above for further details.

Insurance

We believe we maintain prudent levels of insurance coverage in accordance with industry practices in the jurisdictions in which we operate, taking into account the size and scope of our operations and our risk exposure. The insurance we carry includes loss of production insurance that applies to both our Brazilian and USA assets. We typically review on an annual basis the appropriateness of our insurance coverage and amend our policies to any changes in circumstance, being either external market conditions or a change in our business operations. We maintain an insurance program for our participating interest across all operations.

Our insurance does not cover all of the risks and potential losses we face, including because insurance is not available for certain risks, we consider the premiums too high relative to the risk or we elect to self-insure by setting aside amounts of cash or liquid securities that we deem sufficient to cover the occurrence of any such risks. See "Risk factors – Risks relating to our industry and operations – Our insurance arrangements may be inadequate to cover losses arising from our operations" for further details.

Legal proceedings

From time to time, we are involved in disputes with counterparties, joint venture partners, regulators, employees and others in the ordinary course of our business. Given the nature of the oil and gas business, the contractual arrangements we make with joint venture partners, vendors of businesses we acquire, customers of our products and suppliers of equipment and services are often complex and can give rise to disputes due to the complexity of the agreements and the occurrence of circumstances that were not anticipated by the parties. We may also have disagreements with regulators including oil and gas industry regulators and tax authorities about the interpretation of laws and regulations or the application of laws to complex facts. These disputes may involve dispute resolution processes including commercial arbitration and litigation. A number of our agreements contain arbitration clauses that require us to keep arbitration proceedings confidential unless we are required by law to disclose them.

In addition, there continues to be public debate on the environmental and social impact of oil and gas activities. See "Risk factors – Risks relating to our industry and operations – Increasing attention to ESG matters may adversely impact our business and strategic objectives."

We do not expect that the resolution of any of the disputes or debates in which we are currently engaged will have a materially adverse effect on our operations or financial results.

RESERVES AND CONTINGENT RESOURCES

We estimate our petroleum reserves and contingent resources in accordance with the procedures and classifications set out in the Society of Petroleum Engineers (SPE) Petroleum Resource Management System (PRMS) 2018 (PRMS 2018). Australian companies listed on the ASX are required to report their petroleum reserve and contingent resource estimates in accordance with PRMS 2018.

Under PRMS 2018, petroleum reserves are defined as "those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions. Reserves must satisfy four criteria: discovered, recoverable, commercial, and remaining (as of the evaluation's effective date) based on the development project(s) applied."

Reserves are subdivided into three categories in accordance with the level of certainty associated with the estimates: "proved", "probable" and "possible."

Proved reserves (1P) are "those quantities of petroleum that, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable, from a given date forward, from known reservoirs and under defined economic conditions, operating methods, and government regulations. If deterministic methods are used, the term "reasonable certainty" is intended to express a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate."

Probable reserves are "those additional reserves that are less likely to be recovered than proved reserves but more certain to be recovered than possible reserves. It is equally likely that actual remaining quantities recovered will be greater than or less than the sum of the estimated proved plus probable reserves (2P). In this context, when probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the 2P estimate."

Possible reserves are "those additional reserves that analysis of geoscience and engineering data suggest are less likely to be recoverable than probable reserves. The total quantities ultimately recovered from the project have a low probability to exceed the sum of proved plus probable plus possible (3P), which is equivalent to the high estimate scenario. When probabilistic methods are used, there should be at least a 10% probability that the actual quantities recovered will equal or exceed the 3P estimate."

We also present in this offering memorandum our "2C" contingent resources. Contingent resources are "those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations, by the application of development project(s) not currently considered to be commercial owing to one or more contingencies." Contingent resources may include "projects for which there are currently no viable markets, where commercial recovery is dependent upon technology under development, where evaluation of the accumulation is insufficient to clearly assess commerciality, where the development plan is not approved, or where regulator or social acceptance issues may exist." Quantities reported as "2C" contingent resources represent our "best estimate" of our contingent resources. When probabilistic methods are used, there should be at least a 50% probability that the quantities actually recovered will equal or exceed the 2C estimate. We may reclassify our contingent resources into reserves if we are able to establish their commercial viability, which includes the requirement that we evidence a firm intention to proceed with development within a reasonable time-frame.

Readers should apply particular caution to our 3P reserve estimates and our 2C contingent resource estimates. 3P reserves include estimated quantities of hydrocarbons the extraction of which we do not consider probable. Our contingent resources are estimates of hydrocarbon quantities that are not recoverable under current conditions and may never become recoverable. We would not be permitted to disclose our 3P reserves or 2C contingent resources in an SEC registration statement.

Our definitions of proved reserves and probable reserves (under PRMS 2018) vary in certain respects from the definitions of those terms used by the SEC and set out Rule 4-10 of Regulation S-X under the Securities Act. For example, Rule 4-10 requires reserves to be estimated based on existing economic conditions, including prices calculated as the unweighted arithmetic average of the closing price on the first day of each month in the preceding 12-month period at the end of the period covered by the reserves report, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions. We estimate reserves based on contract prices, where applicable, and forecast prices for uncontracted volumes and to estimate contract prices for market-linked contract pricing mechanisms.

The way we assess our share of reserves and contingent resources from the Who Dat assets is different from how we calculate reserves and contingent resources at our Brazilian assets. We report our share of reserves and contingent resources from the Who Dat assets net of royalties owed to the American Office of Natural Resources Revenue (amounting to 12.50%) and any other third parties. This approach is consistent with the SEC reporting system, which considers royalties to be a share of the petroleum reserves to which the license owner does not have title, so that reserves are reported "net" of royalty percentages. This is due to royalties being taken "in-kind" in the United States. This reporting basis is known as net revenue interest, or NRI. Our system of reporting at Baúna treats these royalties as a tax on the revenue generated by the production and sale of hydrocarbons, so that Baúna reserves and contingent resources are generally reported without excluding any percentage for royalties. This reporting basis is generally known as net working interest, or NWI. If the royalties payable under each relevant regime were treated as arising under an "in-kind" royalty regulatory regime, this would decrease our reportable reserves. While the NRI basis of reporting will produce a lower reserves and contingent resources figure when compared to the NWI basis for the same oil or gas field, this will not change our net share of profits from production from that field.

Members of our Reserves Committee consider and assess all proposed changes and additions to our reserves and contingent resources. In doing so, they consider advice and contributions from subject matter experts and external consultants. Our estimates are based on, and fairly represent, information and supporting documents prepared by, or under the supervision of, a qualified petroleum reserves and resources evaluator. Unless noted otherwise, all references to petroleum reserves and contingent resources in this offering memorandum represent our net share. The reference points for our petroleum reserves calculations are at the sales point situated at the relevant production facility.

Our reserves and contingent resources estimates and the recoverability of the quantities of petroleum we have identified as reserves and contingent resources are subject to risk factors associated with the oil and gas industry, which include price fluctuations, actual demand, currency fluctuations, geotechnical factors, drilling and production results, gas commercialization, development progress, operating results, engineering estimates, loss of market, industry competition, environmental risks, physical risks, legislative, fiscal and regulatory developments, economic and financial markets conditions in various countries, approvals and cost estimates. For further discussion of the risks and uncertainties inherent in reserves and contingent resource estimations, see "Risk factors – Risks relating to our industry and operations – Our oil and gas reserve and resource estimates are subject to inherent technical and geological uncertainty and may be revised downwards as a result of lower commodity prices or changed regulation that may result in previously booked reserves no longer being commercially recoverable."

We engage independent experts as required to assist with the integrity of our reserves and contingent resources estimates. We engaged independent experts AGR Energy Services AS, or AGR, and Netherland, Sewell & Associates, Inc., or NSAI, to deliver independent reserves reports for Baúna and for the Dome Patrol and Who Dat oil and gas fields, respectively, as of December 31, 2023. Summaries of those reports have been included in this offering memorandum in Annex A. As of December 31, 2023, AGR's estimate of our 2P reserves in Baúna was approximately 2.5% lower than our estimate of 2P reserves. We have relied upon NSAI's independent reserves report in preparing our estimates of our share of reserves and contingent resources from the Who Dat assets, and any differences between our estimates and the estimates presented by NSAI relate to differences in oil price forecasts. As of December 31, 2023, NSAI's estimate of our share of 2P reserves from the Who Dat assets was approximately 0.6% lower than our estimate of 2P reserves. We believe that the differences between our reserves estimates and those of AGR and NSAI reflect differences in reasonable professional judgment in interpreting data and applying assumptions and are not material.

Reserves and contingent resources estimation using the deterministic method involves an assessment based on discrete estimates made based on available geoscience, engineering, and economic data and corresponds to a given level of certainty. The probabilistic method involves using known geoscience, engineering and economic data to generate a continuous range of estimates and their associated probabilities. We have prepared our petroleum reserves and contingent resources at Baúna using a combination of deterministic and probabilistic methods. AGR used a combination of deterministic and probabilistic methods in estimating our our petroleum reserves and contingent resources at Baúna. NSAI used deterministic methods in estimating our share of petroleum reserves and contingent resources from the Who Dat assets.

The following table sets forth our 1P, 2P and 3P petroleum reserves as of December 31, 2023.

	As of December 31, 2023		
	1P	2P	3P
		(MMboe)	
Brazil			
Baúna[(1)]	37.1	46.5	55.8
Gulf of Mexico			
Who Dat[(2)]	20.9	31.0	43.9
Total	**58.0**	**77.5**	**99.7**

Notes:

(1) Includes reserves from the producing Baúna, Piracaba and Patola oil fields presented on a NWI basis.

(2) Includes our share of reserves from the producing Who Dat, Dome Patrol and Abilene oil and gas fields presented on a NRI basis.

The following table sets forth our 2C petroleum contingent resources as of December 31, 2023.

	As of December 31, 2023
	2C
	(MMboe)
Brazil	
Baúna[(1)]	10.9
Neon[(2)]	60.1
Goia[(3)]	27.0
Gulf of Mexico	
Who Dat East[(4)]	5.4
Total	**103.4**

Notes:

(1) Includes contingent resources from the Baúna, Piracaba and Patola oil fields presented on a NWI basis. These figures reflect the amount of contingent resources we estimate would be recoverable following a potential FPSO life extension.

(2) These contingent resources are assessed within the development unclarified subclass and have not been subject to a commerciality determination. We allocate a contingent resource to this subclass when "project activities are under evaluation and where justification as a commercial development is unknown based on available information." While we report the recoverable resource for the whole field in this contingent resource figure, any finalized development plan may not recover all of these resources. Presented on a NWI basis.

(3) Presented on a NWI basis.

(4) Includes our share of contingent resources in the Who Dat East oil and gas field presented on a NRI basis.

The following tables sets forth our developed, undeveloped and total petroleum reserves as of December 31, 2023. Undeveloped reserves are reserves that we expect to recover: (1) from new wells on undrilled acreage; (2) from deepening existing wells to a different reservoir; or (3) where a relatively large expenditure is required to (a) recomplete an existing well or (b) install production or transportation facilities for primary or improved recovery projects.

	As of December 31, 2023		
	1P reserves		
	Developed	Undeveloped	Total
		(MMboe)	
Brazil			
Baúna[1]	37.1	–	37.1
Gulf of Mexico			
Who Dat[2]	12.3	8.6	20.9
Total	**49.4**	**8.6**	**58.0**

Notes:

(1) Includes reserves from the producing Baúna, Piracaba and Patola oil fields presented on a NWI basis.

(2) Includes our share of reserves from the producing Who Dat, Dome Patrol and Abilene oil and gas fields presented on a NRI basis.

	As of December 31, 2023		
	2P reserves		
	Developed	Undeveloped	Total
		(MMboe)	
Brazil			
Baúna[1]	46.5	–	46.5
Gulf of Mexico			
Who Dat[2]	17.4	13.6	31.0
Total	**63.9**	**13.6**	**77.5**

Notes:

(1) Includes reserves from the producing Baúna, Piracaba and Patola oil fields presented on a NWI basis.

(2) Includes our share of reserves from the producing Who Dat, Dome Patrol and Abilene oil and gas fields presented on a NRI basis.

	As of December 31, 2023		
	3P reserves		
	Developed	Undeveloped	Total
		(MMboe)	
Brazil			
Baúna[1]	55.8	–	55.8
Gulf of Mexico			
Who Dat[2]	24.2	19.7	43.9
Total	**80.0**	**19.7**	**99.7**

Notes:

(1) Includes reserves from the producing Baúna, Piracaba and Patola oil fields presented on a NWI basis.

(2) Includes our share of reserves from the producing Who Dat, Dome Patrol and Abilene oil and gas fields presented on a NRI basis.

The following table sets out the annual changes in our 1P, 2P and 3P reserves from June 30, 2021 to December 31, 2023. We round our reserves figures to the nearest single decimal point, and some totals in the tables below may not add due to rounding. Items that round to zero are represented by the number 0, while items that are actually zero are represented with a dash "–."

	1P reserves reconciliation			**2P reserves reconciliation**			**3P reserves reconciliation**		
	Oil & condensate	**NGL**	**Natural gas**	**Oil & condensate**	**NGL**	**Natural gas**	**Oil & condensate**	**NGL**	**Natural gas**
	(MMbbl)		**(Bcf)**	**(MMbbl)**		**(Bcf)**	**(MMbbl)**		**(Bcf)**
Reserves (as of June 30, 2021)	**41.1**	**–**	**–**	**49.4**	**–**	**–**	**66.1**	**–**	**–**
Production	(4.6)	–	–	(4.6)	–	–	(4.6)	–	–
Reserves (as of June 30, 2022)	**36.5**	**–**	**–**	**44.8**	**–**	**–**	**61.5**	**–**	**–**
Production	(7.0)	–	–	(7.0)	–	–	(7.0)	–	–
Revisions	10.3	–	–	14.0	–	–	6.8	–	–
Reserves (as of June 30, 2023)	**39.8**	**–**	**–**	**51.8**	**–**	**–**	**61.3**	**–**	**–**
Production	(5.5)	(0.0)	(0.2)	(5.5)	0.0	(0.2)	(5.5)	0.0	(0.2)
Revisions	2.6	–	–	0.1	–	–	(0.1)	–	–
Acquisitions	14.0	0.7	37.9	19.6	1.2	61.7	29.2	1.5	80.0
Reserves (as of December 31, 2023)	**50.9**	**0.7**	**37.7**	**66.0**	**1.2**	**61.5**	**84.9**	**1.5**	**79.8**

The following table sets out the annual changes in our 2C contingent resources from June 30, 2021 to December 31, 2023. We round our contingent resources figures to the nearest single decimal point, and some totals in the tables below may not add due to rounding. Items that round to zero are represented by the number 0, while items that are actually zero are represented with a dash "–."

	2C contingent resources		
	Oil & Condensate	**NGL**	**Natural gas**
	(MMbbl)		**(Bcf)**
Contingent resources (as of June 30, 2021)	**86.2**	**–**	**–**
Contingent resources (as of June 30, 2022)	**86.2**	**–**	**–**
Removal of SPS-57 hook-up	(4.2)	–	–
Baúna Life Extension Project	11.1	–	–
Neon post control well drilling	5.1	–	–
Contingent resources (as of June 30, 2023)	**98.2**	**–**	**–**
Acquisitions	1.9	0.0	20.5
Revisions	(0.2)	–	–
Contingent resources (as of December 31, 2023)	99.9	0.0	20.5

Regulatory overview – Brazil

Brazilian Federal Constitution

Pursuant to the Brazilian Federal Constitution, the federal government holds the monopoly on the prospecting, exploitation, development and production, refinery, import and transportation of oil and natural gas, and of other fluid hydrocarbons. The Brazilian Federal Constitution previously prohibited the assignment or concession of any kind of activity involving oil or natural gas exploitation to private companies.

On November 10, 1995, the Brazilian Congress approved Constitutional Amendment No. 9, amending the Brazilian Federal Constitution to permit the federal government to contract with state-owned or private companies the prospecting, refinery, import, transportation, exploration and production of oil and natural gas (*i.e.*, upstream activities) and the refining of derivatives and oil and natural gas (*i.e.*, midstream and downstream activities), subject to applicable law.

Brazilian Oil Law

Federal Law No. 9,478, dated August 6, 1997, or the Brazilian Oil Law, sets forth the rules and principles for contracting upstream, midstream and downstream activities in Brazil. Among other measures, the Brazilian Oil Law:

- reaffirmed the federal government's monopoly on deposits of oil, natural gas and other fluid hydrocarbons and provided that the exploitation and production of these hydrocarbons is regulated and supervised by the federal government;

- created: (i) the CNPE or Brazilian National Council for Energy Policy, a body subordinated to the President of Brazil and responsible for establishing the public policies related to the energy industry; and (ii) ANP, a regulatory agency bound to the Ministry of Mines and Energy, and responsible for regulating upstream, midstream and downstream activities;

- repealed Federal Law No. 2,004/53, pursuant to which the federal government could only exercise its monopoly through Petrobras and its subsidiaries;

- set forth the main terms and conditions applicable to concession agreements pursuant to which the federal government may contract with state-owned or private companies that intend to operate in the refining, development, and production of hydrocarbons; and

- ratified the activities carried out by Petrobras prior to its enactment, granting Petrobras, irrespective of any bidding process, the exclusive right to explore the fields where Petrobras had been producing and the areas in relation to which it could show evidence of previous investments and work.

CNPE

The National Energy Policy Council, or CNPE, created by the Brazilian Oil Law, is a body subordinated to the President of Brazil and led by the Minister of Mines and Energy. CNPE is responsible for establishing the Brazilian energy policies and oil and natural gas production policies and setting forth the guidelines for the bidding processes for the concession of exploitation rights, pursuant to the Brazilian Oil Law.

ANP

The Brazilian Oil Law established the National Agency of Petroleum, Natural Gas, and Biofuels or ANP, a Brazilian federal governmental agency, which is supervised by the Ministry of Mines and Energy. ANP is responsible for regulating the Brazilian oil, natural gas, and biofuels industry. One of ANP's main goals is to create a competitive environment for activities related to oil and natural gas in Brazil, thus resulting in lower prices and better-quality services for consumers, including ensuring fuel supply. Its main responsibilities include: (i) promoting and requiring compliance with Brazilian oil, natural gas and biofuels industry regulations; (ii) carrying out bidding processes for the concession of exploration, development and production rights related to oil, natural gas and biofuels, and entering into, on behalf of the federal government, the relevant concession agreements; (iii) authorizing the transportation, import, export, refining and processing of oil, oil products, natural gas and biofuels; and (iv) overseeing the economic activities of the oil, natural gas and biofuels industries, in each case in accordance with Brazilian interests.

Concession bids

Since 2010, three oil and gas rights regimes have coexisted in Brazil: concession, production sharing, and onerous transfer of rights. In the concession contracts model, the concessionaire takes on all risks and investments in exploration and production. After payment of taxes and government takes, hydrocarbons produced become the exclusive property of the concessionaire, to use or sell at its discretion. In the production sharing contracts model, the private contractor undertakes the exploration and production activities at its own expense and risk. The Brazilian Federal Government's interests in the production sharing regime are represented by Petrobras, which is a party to such contracts and has the right of preference to be operator of the blocks. In the event of a commercial discovery, the contractor receives, as reimbursement, the production volume corresponding to its incurred exploration expenses, also known as cost oil. The government's take of commercial oil discoveries is provided to the Brazilian Federal Government, which distributes it to states and municipalities. The onerous transfer of rights contracts represent areas that Petrobras has exclusivity over until the areas' aggregate production reaches 5 billion barrels of oil and gas. After such milestone, Petrobras has the right to decide which areas to keep and which areas to relinquish to the ANP, which will offer the relevant E&P rights in bidding processes. Karoon's Brazilian blocks were each awarded in concession bids.

To attract private investment, the Brazilian Oil Law established the main terms and conditions to be applied by the federal government when granting concessions for the exploration, development and production of hydrocarbons.

ANP represents the federal government and is responsible for granting concession agreements for the exploration, development and production of oil and natural gas in the Brazilian onshore and offshore sedimentary basins by means of a transparent and competitive bidding process. The only exception to the mandatory bidding process requirement was Round Zero, when concession agreements were granted directly to Petrobras under the onerous transfer of rights regime, dismissing the bidding process, in relation to the exploration blocks where Petrobras had already performed activities and/or made investments before the date of enactment of the Brazilian Oil Law. This direct concession was an acknowledgment of the activities already carried out in these areas by Petrobras, as the sole operator of the former monopoly held by the federal government, and a ratification of its vested rights. From 1999 to 2023, ANP conducted 17 bidding rounds for exploration blocks under the concession regime, and six bidding rounds under the production sharing regime. In addition, ANP has a process of permanently offering areas through accepting bids on new concession blocks in any onshore or offshore basins, with marginal accumulations as well as offering concession fields returned or in the process of being returned to ANP. If determined by the CNPE, the ANP may also include fields or blocks under the production sharing regime (i.e., located in the pre-salt area or in strategic areas) in a permanent offer. As of the date of this offering memorandum, ANP conducted two cycles of permanent offers for blocks under the production sharing regime and is currently conducting the fourth cycle of permanent offers for concession areas.

The definition of the blocks subject to concession is based on geological and geophysical data that indicate the presence of hydrocarbons. In addition, to minimize environmental impacts, ANP, IBAMA and regional environmental agencies make a prior analysis of the areas to be offered.

After that analysis, ANP publishes the requirements for the environmental license regarding the offered blocks, allowing future concessionaires to assess the environmental aspects related to their areas of interest.

The first step of the qualification process to participate in a permanent offer concession bid is the submission of a set of mandatory documents, which constitute the statement of interest. Companies that submit their statement of interest are required to pay a participation fee, which may vary according to the basin where the blocks are located. After payment of the participation fee, they receive a data package with technical information and geological summaries regarding the area.

After this initial stage, qualified companies that decide to continue in the bidding process must undergo a second eligibility review, in which ANP confirms the technical, legal and financial capabilities of these bidding companies in order to present an offer and prior to executing the concession agreement.

Technical qualification. Each company's technical qualification includes its experience in the exploration and production of hydrocarbons. Companies that wish to qualify as operators must submit a technical summary with information that proves their operating capacity. Companies that wish to qualify as non-operators may only participate in a bidding round as members of a consortium led by a qualified operator.

Legal qualification. In order to obtain legal qualification, a company must submit to ANP certain corporate documentation, including its constituent documents and a description of its corporate structure. A foreign company must submit documentary evidence that it was legally formed according to the laws of its country of origin and, if it wins the bidding process, the foreign company must agree to incorporate a company with headquarters and management located in Brazil.

Financial qualification. A company's financial qualification is subject to a minimum shareholders' equity that varies based on each qualifying level. Companies with shareholders' equity below the amount required by ANP cannot participate in the bidding process, except as a member of a consortium, *i.e.*, as a non-operator. The financial qualification is also based on the company's audited financial statements, its bank references and/or other financial documents.

The companies that succeed in this process are then considered eligible to participate in the bidding round and submit an offer. Companies must individually meet all qualification requirements to participate in ANP's bidding rounds and once qualified may present their offers, either alone or as part of a consortium. In the case of a consortium, ANP requires the appointment of a consortium leader to act as the operator responsible for the consortium and the operations, and the other consortium members, even if not operators, are jointly and severally liable for the obligations undertaken under the accession agreement.

ANP analyzes the proposals submitted by the companies and selects the most advantageous offer according to the objective criteria established in the bid notice. Each proposal is scored based on the weighted sum of points given in regard to each evaluation factor. In the last bidding rounds, ANP used a formula that included the following evaluation factors: (i) the signing bonus, accounting for 80% of the score; and (ii) the ANP Minimum Exploratory Program, accounting for 20% of the score. The winners of the bidding round are subject to a second eligibility review, in which the ANP will assess whether or not they meet the minimum technical, legal and financial qualification requirements of the relevant areas at stake.

Once it fulfils these requirements, a company qualifies to enter into a concession agreement with the federal government for those areas for which a winning bid was submitted.

Government participation

Pursuant to the Brazilian Federal Constitution, Brazilian Oil Law and other ANP regulations, concessionaires must pay the following amounts to the federal government:

- signing bonus;
- area occupation or retention fee;
- special participation fee; and
- royalties.

The minimum amount of the signing bonus is established in the bid notice and the final amount is based on the amount of the winning proposal. The signing bonus must be paid upon execution of the concession agreement with ANP.

The occupation or retention fee for the areas under concession is established in the bid notice and must be paid annually. For the calculation of this fee, ANP takes into account, among other factors, the location and the size of the awarded block and the sedimentary basin and its geological features. Decree No. 2,705/98 provides for both minimum and maximum amounts of the occupation or retention fees, in accordance with the stage of the awarded block.

For fields with high production or profitability, a special participation fee may be payable. When payable, this fee is calculated through progressive rates that vary according to the location, lifetime of the field, and production volumes, pursuant to applicable regulations. The special participation fee related to each field is payable on a quarterly basis from the date the high production or profit occurred and is calculated based on the quarterly net revenue of each field, *less*: (i) royalties paid; (ii) investments made in exploitation; (iii) incurred operating costs; and (iv) depreciation and applicable taxes.

ANP is also responsible for determining monthly royalties related to production. Royalties are calculated at a rate ranging from 5% to 10% of the gross revenue from production. For the determination of the royalty percentage applicable to a specific block under concession, ANP takes into account the block's geological risks and the expected production, among other factors.

Pursuant to the Brazilian Oil Law, onshore concessionaires must pay the landowner a special participation fee, ranging from 0.5% to 1.0% of the gross revenue from production of each well located on the owner's land.

On September 21, 2018, ANP enacted ANP Resolution No. 749/2018, which regulates the procedure for granting reduction of royalties as an incentive to incremental production in mature fields.

Article 9 of ANP Resolution No. 749/2018 states that mature fields of small production will have royalties calculated at a rate of five percent (5%) on incremental production. On the other hand, for mature fields of high production, according to the Article 10, the royalties will be calculated by applying regressive rates corresponding to seven and a half percent (7.5%) and five percent (5%), according to the percentage of increase achieved.

Mature fields are classified by Article 2, item III, of the Resolution No. 749/2018 as oil or natural gas field with a history of effective production, carried out from definitive production facilities, greater than or equal to 25 years, or whose accumulated production corresponds to at least seventy percent (70%) of the volume expected to be produced, considering the proved reserves.

"Incremental production" represents the positive difference between the volumes of oil and natural gas actually produced in a given month and the monthly production volumes forecast for this month corresponding to the forecast calculated according to the reference production curve of the field, as stated in the Article 2, item V, of the Resolution No. 749/2018. Baúna field, the sole producing asset in our Brazilian portfolio is a mature field and benefits from this incentive.

On September 28, 2021, ANP published Resolution No. 853/2021, reducing the royalties rate related to fields granted to small and medium-sized companies. The size classification of a company is based on the annual average production of the concession holder, as an independent company or corporate group, pursuant to ANP Resolution No. 32/2014, as follows: (i) companies with annual average production of less than 1,000 boepd are classified as small companies; and (ii) companies with annual average production of less than 10,000 boepd are classified as medium-sized companies.

Following ANP's enactment of resolutions granting a reduction of the royalties rates to: (i) to incremental production in mature fields; and (ii) to small and medium-sized companies, on August 12, 2022, CNPE's published Resolution No. 5/2022, providing for measures to stimulate the development and production of hydrocarbon accumulations in economically viable marginal fields. The oil and gas fields and deposits with economic potential, as well as those corresponding to marginal fields are defined by ANP Resolution No. 877/2022 depending on their production rate, API grade, level of contaminants and reserves reports.

Concession agreements

ANP is responsible for granting concession agreements for the exploration, development and production of oil and natural gas reserves to market players, independently or in joint ventures with other ANP-qualified companies, by means of a transparent and competitive bidding process.

In addition to public biddings, companies in the oil and gas industry may also acquire their participating interest in a specific exploration block or producing field under concessions contracts by means of farm in and farm out (i.e., sale and purchase) agreements. These agreements set forth the percentage of equity interest in the block/field being assigned and are subject to ANP's approval, which is granted upon fulfillment of the technical economic and legal requirements by the assignee, in accordance with the terms and conditions of ANP Resolution No. 785/2019.

The concession agreements executed with ANP set forth the rights and responsibilities of the winning bidders regarding certain exploration blocks, providing for the exploration phase and the production phase. The exploration phase may last from two to eight years and the production phase may last up to 27 years from the date of declaration of commercial feasibility. The production phase may be extended for additional 27 years upon the concessionaire's requires and ANP's approval.

Since the fifth concession bidding round, the concession agreements for hydrocarbon exploration and production started to provide for two exploration periods, and the term of each period is provided for in the applicable concession agreement. In practice, each bidding round will have its own rule.

Each exploration period is subject to an ANP Minimum Exploratory Program, in which the concessionaire agrees to comply with certain obligations, terms and conditions for the development of its activities. The concessionaire must comply with the ANP Minimum Exploratory Program before advancing to the next exploration or production phase.

In the first exploration period, the concessionaire's activities usually consist of geophysical and geochemical surveys and seismic reprocessing related to the concession area. If the concessionaire decides to move on to the second exploration period and has complied with all the ANP Minimum Exploratory Program obligations, the exploration will move on to the drilling of an exploration well. The concession agreements list the activities to be performed during the exploration phase. Moreover, concessionaires must present a financial collateral (letter of credit, insurance bond or oil and gas pledge) to secure the ANP Minimum Exploratory Program, as a condition precedent for the execution of the concession agreement. In the event of noncompliance with the ANP Minimum Exploratory Program, the ANP may foreclose the submitted collateral, without prejudice, and impose sanctions set forth in the applicable legislation.

The exploration phase ends upon submission of a declaration of commercial feasibility, which states that the concessionaire believes it is possible to carry out production in the relevant area. The production phase begins upon delivery of the declaration of commercial feasibility to ANP. The concessionaire then implements the necessary infrastructure and starts producing oil or gas. If the concessionaire decides that the area is not commercially viable, the concessionaire returns it to ANP upon notice and does not initiate the production phase.

Pursuant to the Brazilian Oil Law, the concession agreement must include: (i) the definition of the concession block; (ii) the term of duration and main conditions for exploration and production activities; (iii) the rules and conditions for the partial return and vacation of the concession areas; (iv) the guarantees to be offered by the concessionaire to assure that the concession agreement, including the investments required in each phase, will be complied with; (v) penalties in case the concessionaire fails to comply with the agreement; (vi) the procedures for the assignment of the agreement; (vii) the rules and conditions for the return and full vacancy of the concession areas, with the removal of the equipment and facilities, and reversal of assets; (viii) the procedures to monitor and inspect the exploration, development and production activities, and to audit the agreement; (ix) the obligation of the concessionaire to provide to ANP reports, data and information related to the developed activities; (x) the procedures related to the transfer of the concession agreement, pursuant to Article 29 of the Brazilian Oil Law; (xi) the rules on the resolution of disputes related to the agreement and its performance, including settlement and international arbitration; (xii) the events of termination of the agreement; and (xiii) the penalties applicable in the event of non-compliance by the concessionaire of its contractual obligations.

Concessionaires have the following rights, among others: (i) the exclusive right to the exploration, development and production in the concession area; (ii) ownership of the produced hydrocarbons; (iii) the right to sell the produced hydrocarbons; and (iv) the right to export the hydrocarbons, subject to compliance with obligations regarding domestic supply in the event of declaration of a state of emergency.

The main obligations of a concessionaire include: (i) bearing all costs and risks related to the exploration, development and production of hydrocarbons, including any liability for environmental damages; (ii) complying with the requirements regarding the acquisition of assets and services from domestic suppliers (local content); (iii) complying with the requirements regarding performance under the ANP Minimum Exploratory Program referred to in the winning proposal; (iv) oil reserve conservation; (v) delivering to ANP periodic reports, data and information; (vi) paying government participation fees; (vii) paying the costs related to the deactivation of facilities, pursuant to Brazilian legislation and best practices of the Brazilian oil industry and (viii) following the provisions of the annual work programs.

For additional information on our concession agreements, see "Business – Our concession agreements and leases."

Consortiums and Joint Operating Agreements

In order to minimize the exploration risks and allow for a more diversified portfolio, a number of oil and natural gas companies join consortiums to present proposals. In this case, before the bidding process, companies must execute an agreement for the submission of a joint proposal, which sets forth a timetable for the joint survey of the relevant area and each member's equity interest in the project, among other conditions. In general, the parties share the costs related to the concession area proportionally to their equity interest in the area. Pursuant to Brazilian law, consortium members are jointly and severally liable and, since the consortium does not have its own legal personality, each consortium member must keep separate and independent accounting records.

Once the bidding round ends, before or after the execution of the concession agreement with ANP, consortium members often enter into a joint operating agreement to establish the responsibilities and investments required for the exploration and production of the bid block. These agreements are usually based on a standard agreement form prepared by the Association of International Energy Negotiators, or AIEN. In general, consortia are managed by an operating committee, which is the highest authority of the consortium, responsible for supervising and setting forth guidelines for joint operations.

Bidding Rounds

The most recent and already completed concession bidding rounds include: (i) the 17th bidding round, in 2020, with the offer of 92 blocks in the Campos and Potiguar Sedimentary Basins, as well as in the offshore sedimentary basins of *Pelotas* and *Santos*, totaling an area of 53,900 km^2; and (ii) the 16th bidding round, in 2019, with the offer of 36 blocks in the Campos Sedimentary Basin and in the offshore sedimentary basins of *Pernambuco-Paraíba*, *Jacuípe*, *Camamu-Almada*, and *Santos*, totaling an area of 29,300 km^2.

The last production sharing bidding round was the sixth production sharing bidding round, in 2019, with the offer of the following blocks: *Aram*, *Bumerangue*, *Cruzeiro do Sul*, *Sudoeste de Sagitário* and *Norte de Brava*.

In addition, CNPE Resolution No. 17, dated June 8, 2017, approved the adoption of a permanent offer process, which consists of the continuous offer of returned fields or fields in the process of being returned, and exploration blocks that were not awarded in previous rounds or were returned to the ANP. ANP holds a session for the submission of offers upon receipt of at least one declaration including an offer guarantee for each area of interest. ANP holds this session within 90 days from the date of receipt of the declaration.

The fourth cycle of the permanent offer under concession regime took place in December 2023, with the award of 192 exploratory blocks located in the Potiguar, Espírito Santo, Recôncavo Sedimentary Basins, as well as the *Pelotas, Santos, Paraná, Tucano, Amazonas*, and *Sergipe-Alagoas* sedimentary basins, totaling an area of 47,143.86 km^2. In addition, one marginal accumulation area located in the onshore *Amazonas* sedimentary basin was awarded, totaling an area of 57.29 km^2. Our wholly owned subsidiary Karoon Petróleo e Gas Ltda or KPG, successfully bided for two deepwater exploration blocks located in the Santos basin. KPG is expected to execute the respective concession agreements for these areas within the second quarter of 2024.

Two cycles of the permanent offer under production sharing regime have been carried out by ANP. The second cycle of the permanent offer under production sharing regime took place in December 2023, with the award of one exploratory block located in the *Santos* sedimentary basin, totaling an area of 47,143.86 km^2.

Decommissioning

The decommissioning of oil and natural gas exploration and production systems consists of the permanent interruption of activities associated with the operation of the facilities. It is a legal requirement that the decommissioning process be carried out when the life cycle of the production system ends, and it is an integral part of the oil and gas industry's production cycle.

Once the need for decommissioning has been confirmed, the concessionaire company plans and carries out the activities in accordance with prevailing regulations, including environmental legislation, following strict safety standards and analyzing project alternatives based on multidisciplinary criteria (environmental, technical, safety, social and economic), which allows it to select the decommissioning alternative that generates the least impact. This analysis also considers studies and guidelines on best practices in the oil and gas industry worldwide. As a result of the analysis and prior to initiating the decommissioning of its facilities, the concessionaire shall prepare and submit a decommissioning plan, which must contain all necessary projects, studies and guarantees that would sustain the intended decommissioning work. ANP will then review the presented plan and may authorize the operator of the facilities to start decommissioning the facilities.

The decommissioning process includes various activities, such as disposing of the platform and subsea system and abandoning wells, carried out in accordance with the decommissioning plan approved by the regulatory bodies and in compliance with the applicable legal requirements.

As of the date of this offering memorandum, KPG as the concessionaire has not initiated any decommissioning activities in any of our exploration and production areas in Brazil.

Decommissioning Guarantee

Pursuant to ANP Resolution No. 854 dated September 27, 2021, ANP requests the submission of a financial guarantee to assure decommissioning activities for all concession areas under production phase.

In this context, the concessionaires must engage in discussions about a decommissioning guarantee with the Production and Development Department at ANP under the terms of the ANP Resolution No. 854/2021, which sets out the criteria, rules, and procedures for providing a financial guarantee that ensures financial resources for the decommissioning of production facilities in oil and natural gas fields. The guidelines of the ANP Resolution No. 854/2021 must be observed by concessionaires so that the financial conditions offered for the abandonment activities of oil and natural gas fields are accepted by ANP.

The types of guarantees accepted by ANP are: (i) letter of credit; (ii) guarantee insurance; (iii) pledge of oil and natural gas; (iv) corporate guarantee; or (v) provision fund. For exploration and production agreements not undergoing any assignment processes and that were in force on the date of publication of Resolution No. 854/2021, as amended ANP Resolution No. 925/2023, parties had until October 2, 2023 to comply with the terms of such resolution and implement the necessary adjustments to the guarantees already presented. The acceptance of each financial guarantee is subject to the discretion of ANP, which may order the replacement of the adopted guarantee at any time, whenever a technical study shows that the presented guarantee is insufficient or inadequate.

We currently satisfy the requirements for a decommissioning guarantee, through the presentation of a surety bond in the amount of US$98.2 million and a US$1,000 deposit into a provision fund. The scope of the decommissioning guarantee encompasses all fields included in the BM-S-40 license, which is our only producing asset in Brazil. We are not required to provide decommissioning guarantees with our other non-producing assets in Brazil.

The decommissioning guarantee obligation is reviewed annually in accordance with the published guidelines and adjusted annually for the required guaranteed amount. The revised decommissioning obligation is typically communicated in April of each year. As of the date of this offering memorandum, our guarantee obligation remains subject to finalization with ANP.

A failure to provide the guarantee for the decommissioning in assignment processes pending with the ANP will result in the assignment not being completed, as the guarantee is a requirement set forth in ANP Resolution No. 854/2021. The failure to renew the decommissioning guarantees may cause their foreclosure by ANP, pursuant to ANP Resolution No. 854/21, and subject the concessionaire/contractor to the penalties set forth in Law No. 9,847/1999 for noncompliance with requirements set forth in applicable law and in ANP Resolutions.

Local Content

Local content refers to the contractual obligation arising from a concession contract to meet specific percentage thresholds for sourcing goods, services, and personnel locally. Law No. 12,351/2010 defines local content as the proportion between the amount of goods produced and services performed in Brazil for the performance of an agreement and the total amount of goods and services employed for the same purpose.

In April, 2017, the Brazilian Government announced a significant reduction of the local content requirements for the then current bid rounds. This reduction contributed to the success of Brazil Rounds 14 and 15 under the concession regime, and Pre-Salt Bid Rounds 2, 3, 4 and 5 under the production sharing regime, all held in 2017 and 2018.

In order to address the local content requirements of concession contracts that were granted in previous bid rounds, the ANP published, in April 2018, Resolution No. 726/2018, which regulated amendments to the local content clauses of the concession contracts executed through the Brazil Round 13. It also established rules regarding exemptions (waivers), adjustments of percentages and transfer of local content "excess" in respect of concession contracts awarded under the Brazil Rounds 7 through 13.

ANP Resolution No. 726/2018 permits concessionaires to either: (i) amend concession contracts, in order reduce their local content percentage commitments (in which case they would waive the right to request local content waivers from ANP); or (ii) not amend the concession contracts and maintain the right to request waivers of local content commitments from ANP.

In addition, ANP Resolution 848/2021 established procedures to be followed by concessionaires to execute a conduct adjustment agreement for the replacement of previously assessed local content fines by ANP with new investments in local content in different phases of the concession contract or other concession contracts.

In connection with ANP Resolution 848/2021, we entered into a conduct adjustment agreement that provides that we are not liable for any and all liabilities or local content fines arising in connection with non-compliance of local content requirements incurred prior to the assignment of Blocks S-M-1288 and S-M-1289 (which form part of Baúna), to us, during the exploration phase of Baúna.

ANP further regulated the obligation to evidence compliance with local content requirements by establishing, among other matters: (i) the criteria and audit procedures for the activity of certification of local content (ANP Resolution No. 19/2013); (ii) applicable requirements for local contents reports to be provided by concessionaires to ANP (ANP Resolution No. 871/2022) to prove compliance with the relevant requirements; and (iii) rules for accreditation by a local content certification entity (ANP Resolution No. 963/2023).

Pre-Salt and Strategic Areas

"Pre-salt" refers to a series of hydrocarbon discoveries in the rock layer under a thick layer of salt. These discoveries were in an area approximately 300 to 350 kilometers off the coast of São Paulo, Espírito Santo and Rio de Janeiro states. The discovery of oil and natural gas in the pre-salt area in Brazil led to a new regulatory framework regarding these and other strategic areas. New laws were enacted, including: (i) Law No. 12,276/10, which authorized the federal government to assign the survey and production of oil, natural gas and other fluid hydrocarbons in pre-salt areas that are not under concession granted to Petrobras, representing up to 5.0 billion barrels of oil, which occurred in September 2010; (ii) Law No. 12,351/10, which established the production sharing regime for the pre-salt and other strategic areas; (iii) Law No. 12,304/10, which authorized the formation of the state-owned company Pré-Sal Petróleo S.A., or PPSA, whose corporate purpose is the management of the production sharing agreements executed by the Ministry of Mines and Energy; and (iv) Law No. 13,679/2018, which grants PPSA the right to directly carry out the sale of oil, natural gas and other fluid hydrocarbons of the federal government. Under the production sharing regime, the Brazilian government awards agreements to private companies for the exploration and production of oil and natural gas, pursuant to which these companies are entitled to a share in the production.

Conversely, under the concession regime, the concessionaire is the owner of the entire production, subject to the payment of the government's share, pursuant to the Brazilian Oil Law and the relevant concession agreements. Under the production sharing agreement, the contractor performs the exploration, assessment, development and production activities at its own risk. In the event of a commercial discovery, the contractor receives, as reimbursement, the production volume corresponding to its incurred exploration expenses also known as cost oil. In addition to cost oil, the contractor receives the production volumes corresponding to payable royalties and profit oil or excess oil, in the proportion, conditions and terms set forth in the agreement. The structure proposed by the Brazilian government also includes these traditional concepts of cost oil, whose limits are determined in each agreement, and profit oil. In bidding processes, agreements are awarded to the companies that offer the highest percentage of profit oil to the government, above the percentage limit set forth in the bidding process. In a production sharing partnership, a state-owned company is specially formed to act on behalf of the government.

Pursuant to Law No. 13,365/16, which amended Law No. 12,351/10, or the Sharing Regime Law, Petrobras is no longer required to act as operator in all the blocks under the production sharing regime. Pursuant to the amended Sharing Regime Law, CNPE will grant Petrobras the right of first refusal to operate the blocks to be awarded.

The partnership between the Brazilian government and the consortium, which includes Petrobras and private partners, is managed by an operating board. The Brazilian government elects 50% of the members of the operating board, including the chairman, who has the casting vote and veto rights. The operating board is responsible for all important management and operating decisions regarding the partnership, including decisions on investments and production segregation arrangements, or production unitization.

The first production sharing bidding round occurred in 2013, with the offer of the *Libra* oil field, in the Campos Sedimentary Basin. Even though eleven companies confirmed their interest in the offer, only one consortium, comprising Petrobras, Shell, Total, CNPC and CNOOC, submitted an offer, thus winning the bid. CNPE authorized the seventh and eighth production sharing bidding rounds, the 18th concession bidding round, and the aforementioned permanent concession offer.

More recently, CNPE Resolution No. 26/2021 was published, allowing for the first time, bidding rounds of blocks under the production sharing regime through the permanent offer model. Until then, the permanent offer only covered areas to be offered under the concession regime. In December 2023, ANP carried out the fourth bidding round of the permanent concession offer. A total of 192 exploratory blocks were auctioned in all nine sedimentary basins that had areas on offer, a record number in the bids held to date in this modality. The previous record was recorded in the Third Cycle, when 59 blocks were sold.

Brazilian Competition Law

Certain corporate transactions, including the acquisition of assets and the formation of joint ventures, consortia and collaborative agreements (the so-called *Contratos Associativos*), including those conducted under farm-in and farm-out agreements, are subject to the Brazilian Pre-Merger Control System if they meet the applicable thresholds, pursuant to Law No. 12,529, dated November 30, 2011. Accordingly, these transactions may be subject to both ANP's and the Brazilian Administrative Council for Economic Defense's prior approval and cannot be completed before such approvals are duly granted, pursuant to Article 88 of Law No. 12,529/2011. Failure to comply with this obligation exposes all the parties involved in the transaction to the following consequences: (i) fine ranging from R$60,000 to R$60.0 million; (ii) the transaction may be deemed null and void; and (iii) opening of an investigation for anticompetitive behavior due to the practices carried out post-closing.

Environmental Regulations

In view of the specific requirements set forth in the laws of certain locations in which we operate, a portion of our activities is subject to environmental licenses issued by federal, state or municipal environmental authorities. We strive to meet and adjust to the terms and conditions ser forth in these licenses.

Environmental Licensing

The Brazilian Environmental Policy, established by Law No. 6,938/1981, provides that all potentially or effectively polluting activities are subject to an environmental licensing process (without prejudice to other licenses and authorizations legally required). The environmental licensing process encompasses three different stages, including the granting of the preliminary license (*licença prévia*), the installation license (*licença de instalação*) and the operating license (*licença de operação*).

However, this licensing process may be simplified, encompassing only one stage, upon the issuance of the simplified environmental license (*licença ambiental simplificada*) or the single environmental license (*licença ambiental única*), subject to the laws and regulations of the involved licensing agencies and, to different extents, the characteristics of each project, including the region, size, construction characteristics, polluting potential and level of impact, among others.

In any event, the aforementioned environmental licenses expire and must be periodically and timely renewed. Pursuant to Complementary Law No. 140/2011, the renewal of any environmental license must be requested at least 120 days before the expiration date to be automatically extended until the environmental agency issues its final decision. Certain environmental licenses may set forth technical conditions for the development of activities that have an environmental impact, under penalty of cancellation of the relevant license.

Failure to obtain licenses or authorizations from the competent environmental agencies for the conception, construction, change, expansion and operation of activities and/or potentially polluting projects, or operations in disagreement with the issued environmental licenses, as well as to the non-compliance with the conditions set forth on such licenses may subject offenders to criminal and administrative penalties, in addition to the obligation to repair any environmental damages. Applicable administrative penalties to this issue include fines, ranging from R$500.00 to R$10.0 million, pursuant to Federal Decree No. 6,514/2008, which regulates Federal Law No. 9,605/1998. State and municipal governments may provide for environmental protection and impose fines in different amounts.

Solid Waste

The Brazilian Solid Waste Policy, established by Federal Law No. 12,305/2010, sets forth the principles, instruments, guidelines, targets and actions related to the integrated and environmentally adequate management of solid waste, except radioactive waste, which is subject to specific laws. Generators of solid waste are responsible for its environmentally adequate segregation, storage, transportation and final disposal, and may be required to repair any environmental damages resulting from the inadequate management of this waste.

The Brazilian Solid Waste Policy established the shared responsibility, pursuant to which the tasks and costs involved in the different stages of management of solid waste are shared by the entire production chain, in proportion to the liability of each of the involved parties. Accordingly, even though the civil liability for repairing environment damages is joint and several, strict and tort-based, the administrative liability for managing solid waste divides the burden among the parties involved in the chain.

Accordingly, the engagement of third parties to perform any of the stages of the management of solid waste, including the environmentally adequate final disposal, does not exempt us from liability for any environmental damage caused by the engaged third parties.

The inadequate disposal of solid waste may subject offenders to administrative, criminal and/or civil liability.

Pursuant to Federal Decree No. 6,514/2008, discharging solid, liquid or gaseous wastes or debris, oils or oily substances in violation of the requirements established by legislation, as well as failure, by the party with an obligation, to dispose of products, oil derivatives, packages, residues or substances in an environmentally appropriate manner when so determined by legislation, subjects offenders to potential administrative liability penalties, including fines of up to R$50.0 million. Pursuant to Federal Law No. 9,605/1998, or the Brazilian Environmental Crimes Law, discharging solid, liquid or gaseous wastes or debris, oils or oily substances in violation of the requirements established by legislation, subjects offenders to potential criminal liability, including imprisonment for one to five years and a fine. In the event of unintentional crime, offenders are subject to imprisonment for six months to one year and a fine. These penalties may be applied without prejudice to the obligation to repair the environmental damages.

Contaminated Areas

Contaminated areas are sites that have been confirmedly polluted by the disposal, accumulation, storage or infiltration of substances or waste, resulting in negative impacts on the assets to be protected.

Pursuant to Brazilian environmental laws, the owner and/or possessor of a real estate property located in an environmentally contaminated area may be held liable and required to remediate and repair the associated damages, whether they caused the damages or not, by determination of environmental agencies and the Prosecutor's Office.

Environmental civil liability for repairing the contamination of the soil and underground waters is strict, joint and several and is considered to be a *propter rem* obligation, which is an obligation that accompanies the real estate property.

Causing pollution of any nature in levels that result or may result in damage to human health or that cause the death of animals or a significant destruction of biodiversity is an administrative infraction that subjects offenders to administrative fines ranging from R$5,000.00 to R$50.0 million, as well as an environmental crime, and imposes the obligation to repair the environment.

Environmental Liability

Environmental liability encompasses the following different and independent liabilities: (i) civil liability; (ii) administrative liability; and (iii) criminal liability. These liabilities are different and independent because one single action may result in environmental liability at these three levels, including the application of administrative and criminal penalties, in addition to the obligation to repair the damage caused. Conversely, the lack of liability at any of these levels does not necessarily exempt offenders from liability on the other levels.

Environmental civil liability is strict, *i.e.*, it is not subject to the existence of fault. The confirmation of the damage and the causation between the damage and the activity of a company suffices to subject offenders to the obligation of repairing the damage. Irrespective of the existence of fault, the party that causes the pollution is required to indemnify and/or repair the damages caused to the environment and third parties as a result of the party's activities. Accordingly, environmental civil liability is attributed to the party that is directly or indirectly responsible for the activity that caused the environmental damage. Moreover, if the activity is conducted by more than one party and it is not possible to identify the contribution of each party to the environmental damage, government agencies and courts have been imposing joint and several liability on the party that is able to bear the entire environmental damage, having right of recourse against the other involved parties. Environmental civil liability is joint and several and is not subject to the statute of limitations. As a result, the engagement of third parties to provide any service in our units, including the suppression of vegetation, and the transportation and final disposal of waste, does not exempt us from liability for any environmental damages caused if these third parties do not perform their activities in compliance with environmental regulations. Brazilian civil liability environmental law provides for the piercing of the corporate veil of entities that commit environmental infractions whenever it represents an obstacle for repairing environmental damages. Potential criminal liability under the Brazilian Environmental Crimes Law applies to any individual or corporation that contributes to environmental crimes, upon confirmation of intent, *i.e.*, the free will to produce the result, or fault, *i.e.*, the lack of the necessary care, including negligence, recklessness or lack of skill. Accordingly, the imposition of criminal liability requires the confirmation of an action or omission, and the alleged conduct must be enumerated as a crime under the relevant laws. Potential criminal penalties for individuals include imprisonment; restriction of rights, including community services, temporary interdiction of rights, partial or full suspension of activities, pecuniary indemnification or house confinement (*recolhimento domiciliar*); and fines. Restriction of rights is an independent penalty and may replace imprisonment in certain cases. Potential criminal penalties for corporations include: restriction of rights, including the partial or full suspension of activities, temporary interdiction of facilities, construction or activity, or prohibition to contract with the government and obtain government subsidies, incentives or donations; community services; and fines. Individuals and corporations are subject to fines ranging from one-third of to 1,800 times the minimum wage in effect at the time of the facts, based on their culpability.

Potential administrative liability under the Brazilian Environmental Crimes Law, regulated by Federal Decree No. 6,514/2008, exists for all actions or omissions that violate the provisions on the use, enjoyment, promotion, protection and recovery of the environment. Administrative liability derived from an action or omission of the agent that results in the violation of any rule on environmental preservation, protection or regulation and, similarly to criminal liability, is subject to the confirmation of fault or intent, pursuant to the court precedents of the Superior Court of Justice (*Superior Tribunal de Justiça*). However, certain environmental agencies continue to impose strict administrative liability regarding environmental infractions. Administrative penalties include warning; fines of up to R$50.0 million, which may be doubled or tripled in the event of recidivism; destruction of the product whose production caused the environmental damage; suspension of the sale and manufacturing of the product; interdiction of the construction or activity; demolition of construction; suspension of tax benefits and the cancellation or interruption of credit facilities granted by government banks, in addition to the prohibition to contract with the government.

The Prosecutor's Office and environmental agencies may initiate administrative procedures to investigate any environmental damages that may be attributed to our activities. In these cases, we may enter into conduct adjustment instruments (*Termos de Ajustamento de Condutas*), or TACs, and/or generic commitment instrument (*Termos de Compromissos*), or TCs, with the relevant authorities, assuming specific obligations for a certain time. TACs and TCs are out-of-court enforceable instruments and, as a result, in the event of full or partial non-compliance with TACs and/or TCs, we may be subject to risks and penalties, including the payment of fines, enforcement of these instruments and the filing of proceedings with courts.

In addition to licenses, we may be required to obtain certain authorizations issued by environmental agencies, including in regard to the suppression of vegetation, use of water resources, treatment of effluents and management of waste, among others. Also, we are required to observe applicable rules to preserve and (re)forest protected areas as well as rules related to impacts on traditional communities and historical heritage.

Carbon credits and the Brazilian Greenhouse Gas Emissions Trading System

On December 21, 2023, the Brazilian House of Representatives approved a bill to create a Brazilian Greenhouse Gas Emissions Trading System. Subject to the approval of the bill by both houses of the Brazilian parliament, Karoon, which has facilities or sources that may emit greater than 10,000 tCO_2/e per year, is likely to be considered a regulated entity under the scope of the regulation, which may impose reporting and other requirements on us. Under the currently proposed rules, we would be required to acquire assets, which are also known as SBCE assets, through the trading system. These assets include Brazilian Emissions Quotas, which are similar to the European Union Emissions Trading System, and Verified Emission Reduction Certificates. A portion (which is not yet defined) of the Verified Emission Reduction Certificates could be originated from voluntary carbon credits that meet certain legal requirements. As of the date of this offering memorandum, the implementation and timeline for a Brazilian carbon market remains uncertain. See also "Risk factors – Risks relating to our regulatory, tax and legal environment – Our business is subject to extensive laws and regulations that are subject to change in ways that could adversely affect our business and financial position."

Data Protection and the Brazilian General Data Protection Law

Data privacy and protection laws have evolved in recent years to provide for more detailed rules on how companies may process personal data, *i.e.*, any information related to an identified or identifiable individual.

Until August 2018, when the Brazilian General Data Protection Law (Law No. 13,709/18, or LGPD), was enacted, practices related to the processing of personal data were regulated by sparse legislation and industry-specific regulations.

With the enactment of LGPD on September 18, 2020, Brazil has adopted more robust rules for the processing of personal data, with stronger requirements, applicable across all industries. Inspired by the European Union's General Data Protection Regulation (the GDPR), the LGPD creates a framework in which individuals have more control over their personal data and companies that process this type of information have more responsibilities.

Privacy rights in Brazil are also protected by the Brazilian Federal Constitution and Law No. 10,406/02, or the Brazilian Civil Code of 2002. In addition, Brazilian Constitutional Amendment No. 115 of February 10, 2022, includes the protection of personal data among the fundamental rights and guarantees provided for in the Brazilian Federal Constitution.

The LGPD applies to individuals and public and private entities, regardless of the country where they are based or where the data is hosted, provided that (i) the data processing activity is carried out in Brazil; (ii) the data processing activity is intended to offer goods or services to, or processes data of, individuals located in Brazil; or (iii) the personal data involved in the data processing have been collected in Brazil. The Brazilian General Data Protection Law applies to all industries and businesses processing personal data and is not restricted only to data processing activities carried out via digital media and/or over the internet, but is also applied in the physical environment.

The LGPD provides for, among others, the obligation of transparency by data controllers, the rights of data subjects, the obligation to define the legal basis for processing personal data, the obligation to appoint a data protection officer (*encarregado*), rules applicable to information security incidents involving personal data, the implementation of a privacy governance program as a best practice, as well as the requirements and obligations for international data transfers.

In addition, the LGPD establishes the role of the National Data Protection Authority (*Autoridade Nacional de Proteção de Dados*), or ANPD, which is responsible for protecting, implementing and inspecting compliance with the LGPD, as well as for: (i) investigation of data processing incidents, including the power to enact standards and procedures, interpretation of the LGPD and power to request information from data controllers and processors; (ii) enforcement, in cases of violations, via administrative proceedings; and (iii) education, including disseminating information and fostering awareness of the LGPD and safety measures, promoting best practices for services and products that facilitate data control, and producing studies about national and international practices for the protection of personal data and privacy, among others.

We have a personal data privacy governance program to comply with the guidelines and requirements presented by the LGPD. Furthermore, we have data protection policies and safeguards based on best industry practices. As of the date of this offering memorandum, we have adopted measures in compliance with the LGPD, such as the appointment of a personal data protection officer or DPO. We have appointed a specialized legal consultancy office to perform the role of our data protection officer. The data protection officer is responsible for, among others, providing the necessary technical and legal support to assist us in the effective implementation of our privacy governance program, ensuring that we process personal data in compliance with privacy and data protection rules, as well as responding to data subject requests and interacting with the ANPD.

Our privacy and personal data protection governance program demonstrates our commitment to adopting internal processes and policies that ensure comprehensive compliance with standards and best practices relating to data protection and the privacy of data subjects, as well as cybersecurity.

We also implemented privacy notices to provide information on the processing activities we carry out. These include (i) an internal privacy and data protection notice, which applies to all internal employees who have or had a relationship with us; and (ii) a privacy and data protection notice with the aim of bringing transparency to data subjects such as customers, business partners, investors and any other interested party that has a relationship with us, as well as service providers, suppliers, employment candidates and all groups and companies that have or had a relationship with us.

For additional information, see "Risk factors – Risks relating to our regulatory, tax and legal environment – Our business, practices and policies are subject to risks associated with non-compliance with the Brazilian General Data Protection Law and could be adversely affected by the application of penalties, including fines and indemnifications."

Regulatory overview – US Gulf of Mexico

Within the United States, our operations are subject to complex and stringent federal, state and local laws and regulations that govern the issuance of permits to conduct exploration, drilling and production operations, the amounts and types of materials that may be discharged or emitted into the environment, and the handling, treatment, storage and disposal of waste material. There are also laws and regulations requiring the remediation of releases of hazardous substances, pollutants and contaminants into the environment, including in connection with waste materials that are transported from offsite facilities and disposed of in onshore facilities.

Environmental regulation

The federal environmental laws and regulations applicable to us and our operations include, among others, the following:

- *U.S. Comprehensive Environmental Response, Compensation and Liability Act ("CERCLA").* CERCLA and analogous state statutes impose liability for the investigation and cleanup of releases of hazardous substances, pollutants, and contaminants into the environment on, among others, current and former owners and operators of contaminated properties, and parties that disposed of, or arranged for the disposal of, such substances at third-party disposal sites. CERCLA liability is joint and several. A liable party may be required to clean up all of the contamination at a site even if it contributed only a percentage of the total substances released at the site. CERCLA liability is no fault. A liable party may be required to clean up contamination even if the original activities, including disposal activities, accorded with all then applicable regulatory requirements. Although CERCLA generally exempts "petroleum" from regulation, in the course of our operations, we could generate wastes that fall within CERCLA's definition of hazardous substances, pollutants or contaminants, and may have disposed of these wastes at disposal sites, owned and operated by others, where releases to the environmental subsequently occurred.

- *U.S. Clean Water Act ("CWA").* Discharges into waters of the United States are limited by the CWA and analogous state statutes. The CWA prohibits any discharge of pollutants, including spills and leaks of oil and other substances, into waters of the United States, except in compliance with permits issued by federal and state governmental agencies. These discharge permits also include monitoring and reporting obligations. Failure to comply with the CWA, including discharge limits set by permits issued pursuant to the CWA, may result in administrative, civil or criminal enforcement actions. Violations of the CWA can result in suspension, debarment or the imposition of statutory disability, each of which prevents companies and individuals from participating in government contracts and receiving some non-procurement government benefits. The CWA also requires the preparation of oil spill response plans and spill prevention, control and countermeasure plans.

- *U.S. Oil Pollution Act ("OPA").* OPA holds owners and operators of offshore oil production or handling facilities, including the lessee or permittee of the area where an offshore facility is located, strictly liable for the costs of removing oil discharged into waters of the United States and for certain damages from such spills. OPA assigns joint and several, and strict, liability, to each liable party for all containment and oil removal costs and a variety of public and private damages including, but not limited to, the costs of responding to a release of oil, natural resource damages and economic damages suffered by persons adversely affected by an oil spill. Although defenses exist to the liability imposed by OPA, they are limited. OPA's damages liability cap is currently $167.8 million; however, a party cannot take advantage of liability limits if a spill was caused by gross negligence or willful misconduct, resulted from violation of a federal safety, construction or operating regulations, or if the party failed to report a spill or cooperate fully in the clean-up. OPA also requires responsible parties to maintain evidence of financial responsibility in prescribed amounts. OPA currently requires a minimum financial responsibility demonstration of between $35 million to $150 million, based on a worst-case oil spill discharge volume, for companies operating on the OCS.

- *U.S. Clean Air Act ("CAA").* The CAA and analogous statutes restrict the emission of air pollutants and affect both onshore and offshore oil and natural gas operations. New facilities may be required to obtain separate construction and operating permits before construction work can begin or operations may start, and existing facilities may be required to incur capital costs in order to remain in compliance. Also, the Environmental Protection Agency ("EPA") has developed, and continues to develop, more stringent regulations governing emissions of toxic air pollutants.

- *U.S. Endangered Species Act ("ESA"); U.S. Migratory Bird Treaty Act ("MBTA") and U.S. Marine Mammals Protection Act ("MMPA").* The ESA restricts activities that may affect federally identified endangered and threatened species or their habitats. Additionally, the MBTA implements various treaties and conventions between the United States and certain other nations for the protection of migratory birds. Under the MBTA, the taking, killing or possessing of migratory birds is unlawful without a permit. The MMPA similarly prohibits the taking of marine mammals without authorization.

  The U.S. Fish and Wildlife Service ("FWS") under former President Trump issued a final rule on January 7, 2021, limiting the scope of the MBTA, including by interpreting the MBTA as only prohibiting the intentional take of migratory birds (i.e., actions "directed at" migratory birds, their nests or their eggs). In October 2021, however, the FWS under the Biden Administration revoked the Trump Administration's rule and returned to its prior interpretation that both intentional and incidental takes of migratory birds are prohibited. The FWS also published an advanced notice of proposed rulemaking to codify a general prohibition on incidental takes while establishing a process to regulate or permit exceptions to such a prohibition.

  The FWS under former President Trump also issued rules limiting the scope of the ESA. These have largely been revoked or superseded by rules issued by the FWS under President Biden. For example, on March 28, 2024 the FWS finalized three rules under the ESA that revise Trump-era regulations and strengthen protections for plants and animals. The new rules include restoring the so-called blanket rule, which automatically extends protection for endangered species to threatened species; affirming that listing determinations are made without reference to possible economic impacts; and clarifying standards for delisting species. The rules are expected to become effective on May 6, 2024. On April 12, 2024, the FWS also issued a final rule that expedites the process of issuing enhancement and survival permits, and incidental take permits. Under the rule, an enhancement or survival permit is appropriate for authorizing takes for scientific purposes or to enhance the survival of a species, while an incidental permit remains appropriate for authorizing takes incidental to lawful resource extraction, commercial development, and energy infrastructure.

  Additionally when the FWS makes determinations on the listing of species as threatened or endangered under the ESA, litigation with respect to the listing or non-listing may result in more fulsome protections for non-protected or lesser-protected species. Moreover, the FWS or the National Marine Fisheries Service ("NMFS") may designate critical habitat that it believes is necessary for survival of a threatened or endangered species. A critical habitat designation could result in further material restrictions to federal land use and may materially delay or prohibit access to protected areas for oil and natural gas development. For example, in April 2019, the NMFS listed the Rice's whale, determined to be a subspecies of the Bryde's whale, as endangered under the ESA. On July 24, 2023, NMFS proposed to designate approximately 28,270.65 square miles of the Gulf of Mexico as critical habitat for the Rice's whale. NMFS is currently reviewing comments and is expected to issue a final critical habitat designation for the Rice's whale in 2024. These statutes may result in operating restrictions or a temporary, seasonal or permanent ban in affected areas.

- *U.S. Resource Conservation and Recovery Act ("RCRA").* RCRA generally regulates the disposal of solid and hazardous wastes and imposes certain environmental cleanup obligations. Although RCRA specifically excludes from the definition of hazardous waste "drilling fluids, produced waters and other wastes associated with the exploration, development or production of crude oil, natural gas or geothermal energy," the EPA and state agencies may regulate these wastes as solid wastes. However, it is possible that certain oil and natural gas drilling and production wastes now classified as non-hazardous could be classified as hazardous wastes in the future. Any future loss of the RCRA exclusion for drilling fluids, produced waters and related wastes could result in increased costs to manage and dispose of generated wastes. Also, ordinary industrial wastes, such as paint wastes, waste solvents, laboratory wastes and waste oils, may be regulated as hazardous waste.

- *U.S. National Environmental Policy Act ("NEPA").* NEPA requires federal agencies, including the DOI, to consider the impacts their actions have on the human environment, and to prepare detailed statements for major federal actions having the potential to significantly impact the environment. These requirements can lead to additional costs and delays in permitting for operators as the DOI or its bureaus may need to prepare Environmental Assessments ("EA") and more detailed Environmental Impact Statements ("EIS") in support of its leasing and other activities that have the potential to significantly affect the quality of the environment. If the EA indicates that no significant impact is likely, then the agency can release a finding of no significant impact and carry on with the proposed action. Otherwise, the agency must then conduct a full-scale EIS.

  The Biden Administration announced in October 2021 that it intended to issue new rules that would authorize agencies to consider direct, indirect and cumulative effects of major federal actions including upstream and downstream GHG emissions impacts of fossil fuel projects, allowing agencies to determine the purpose and need of a project, which allows consideration of less-harmful alternatives, and affording agencies greater flexibility in crafting their own NEPA procedures, consistent with Council on Environmental Quality ("CEQ") regulations, so as to meet the agencies' and public's needs. In April 2022, the CEQ issued a final rule in line with the proposed changes, a move considered as "Phase I" of the Biden Administration's two-phased approach to modifying NEPA. On July 28, 2023, the CEQ announced a "Phase 2" Notice of Proposed Rulemaking, the "Bipartisan Permitting Reform Implementation Rule," which revises the implementing regulations of the procedural provisions of NEPA and implements the amendments to NEPA included in the June 3, 2023, Fiscal Responsibility Act of 2023. The public comment period for the proposed rule closed on September 29, 2023, and the final rule is expected in the second quarter of 2024. Additionally, in January 2023, the CEQ released guidance to assist federal agencies in assessing the GHG emissions and climate change effects of their proposed actions under NEPA. The CEQ's interim guidance, effective upon publication, encourages agencies to consider, among other things, effects from upstream and downstream GHG emissions of fossil fuel projects and, in many cases, use estimates of the social costs of GHG emissions when communicating those findings to the public. The NEPA process involves public input through comment. These comments, as well as the agency's analysis of the proposed project, can result in changes to the nature of a proposed project, such as by limiting the scope of the project or requiring resource-specific mitigation. The adequacy of the agency's NEPA process can be challenged in federal court by process participants. This process may result in delaying the permitting and development of projects and result in increased costs.

- *U.S. Bureau of Ocean Energy Management ("BOEM"), the U.S. Bureau of Safety and Environmental Enforcement ("BSEE"), and Office of Natural Resources Revenue ("ONRR") requirements*. Federal oil and natural gas leases in the U.S. Gulf of Mexico are subject to extensive regulation by BSEE, the BOEM and the ONRR under the purview of the DOI. Federal leases are awarded by BOEM based on competitive bidding with relatively standardized lease terms and require compliance with detailed BSEE and BOEM regulations and orders issued pursuant to various federal laws, including the federal Outer Continental Shelf Lands Act ("OCSLA"). For offshore operations, lessees must obtain BOEM approval for exploration, development and production plans prior to the commencement of their operations. Lessees must obtain a permit from BSEE prior to the commencement of drilling and comply with regulations governing, among other things, engineering and construction specifications for production facilities, safety procedures, plugging and abandoning of wells on the OCS, calculation of and valuation of production related to royalty payments, and decommissioning of facilities, structures and pipelines.

The Biden Administration has taken a number of actions to adopt more stringent safety, permitting and performance requirements. For example, on August 23, 2023, BSEE published a final well control rule for drilling, workover, completion and decommissioning operations, revising the 2019 rule and increasing the requirements for blowout preventer systems ("BOPs") and other well control and operations requirements. The final rule requires, among other things, that BOPs are always able to close and seal the wellbore to the well's maximum anticipated surface pressure, failure analysis and investigations start within 90 days of an incident, failure data is reported to both a designated third party and BSEE, and independent third-party qualifications are submitted to BSEE with associated permit applications.

There has been substantial uncertainty with respect to BOEM's financial assurance requirements in recent years and BSEE's approach to predecessor liability for decommissioning obligations. In April 2023, BSEE published its Final Rule entitled, "Risk Management, Financial Assurance, and Loss Prevention – Decommissioning Activities and Obligations," wherein BSEE clarified decommissioning responsibilities for right-of-use and easement grant holders and formalized BSEE's policies regarding performance by predecessors ordered to decommission OCS facilities. The final rule withdraws a rule proposed during the Trump Administration that sought to amend BSEE's regulations requiring the agency to proceed in reverse chronological order against predecessor lessees, owners of operating rights and grant holders when requiring such entities to perform their accrued decommissioning obligations upon failure to perform by current lessees, owners, or holders. Under the final rule, BSEE may issue an order to predecessors to perform accrued decommissioning obligations, including beginning maintenance and monitoring within thirty days, designating an operator for decommissioning within ninety days, and submitting a decommissioning plan within one hundred fifty days.

In addition, on April 15, 2024 BOEM announced a final rule that substantially revises the supplemental financial assurance requirements applicable to offshore oil and gas operations. The final rule is expected to be published in the *Federal Register* later in April and to become effective 60 days after publication. The rule changes the criteria used to determine whether OCS lease and grant holders are required to secure supplemental financial assurance. The rule replaces the 5-point test (based on financial capacity; projected financial strength; business stability; record of compliance with existing rules and regulations; and reliability) with a a simplified test: (i) the credit rating of the lessee and, where applicable, (ii) the ratio of the value of proved oil and gas reserves of the lease to the estimated decommissioning liability associated with the reserves. Under the rule, BOEM will no longer consider or rely upon the financial strength of predecessors in determining whether, or how much, supplemental financial assurance should be provided by current lessees and grant holders. BOEM will not require supplemental financial assurance above the base bond requirements in three cases: (i) where a lessee has an investment grade credit rating (i.e., a credit rating from a Nationally Recognized Statistical Ratings Organizations ("NRSRO") that is greater than or equal to either BBB- from S&P or Baa3 from Moody's, or its equivalent, or a proxy credit rating greater than or equal to either BBB- or Baa3, as determined by the Regional Director of such NRSRO and based upon a company's audited financial information with an accompanying auditor's certificate); (ii) where there are multiple co-lessees on a lease and any one of those lessees meets the credit rating threshold; or (iii) for any lease on which all lessees are rated below investment grade, where the value of the lease's proved oil and gas reserves is at least three times that of the estimated decommissioning cost estimate. We are currently assessing the impact of the revised rule.

Separately, in August 2021, BOEM published a Note to Stakeholders detailing an expansion of its supplemental financial assurance requirements currently applicable to all sole liability properties and now to certain high-risk, non-sole liability properties; namely, those properties that are inactive, where production end-of-life is fewer than five years, or with damaged infrastructure irrespective of the remaining property life of the surrounding producing assets. BOEM has stated it will prioritize non-sole liability properties where it believes that the current owner does not meet applicable requirements related to financial strength and has no co-owners or predecessors that are financially strong, as determined by BOEM.

Health and safety

The joint venture is also subject to the requirements of the Occupational Safety and Health Administration ("OSHA") and analogous state statutes, where applicable. These laws and the implementing regulations strictly govern the protection of the health and safety of employees. The OSHA hazard communication standard, the EPA community right-to-know regulations under Title III of CERCLA and similar state statutes, where applicable, require that we organize and/or disclose information about hazardous materials used or produced in our operations. Such laws and regulations also require that workplaces meet prescribed safety standards and provide for compensation to employees injured as a result of our failure to meet these standards as well as civil and/or criminal penalties in certain circumstances. We believe that our operations are in substantial compliance with all applicable existing laws and regulations.

Other oil and gas industry regulations

The oil and natural gas industry is extensively regulated by numerous U.S. federal, state and local authorities. Rules and regulations affecting the oil and natural gas industry are under consistent review for amendment or expansion, which could increase the regulatory burden and the potential sanctions for noncompliance. Relatedly, numerous federal and state departments and agencies are authorized to issue rules and regulations binding on the oil and natural gas industry and its individual members, some of which carry substantial penalties for failure to comply.

Exploration and production by our joint venture are subject to various types of regulation at the federal, state and local levels. These types of regulation include requiring permits for the drilling of wells, drilling bonds and reports concerning operations. Our joint venture may face requirements for (i) the location of wells; (ii) the method of drilling and casing wells; (iii) the plugging and abandonment of wells and, following cessation of operations, the removal or appropriate abandonment of all production facilities, structures and pipelines; and (iv) the produced water and disposal of wastewater, drilling fluids and other liquids and solids utilized or produced in the drilling and extraction process.

Our joint venture's operations on federal oil and natural gas leases in the US Gulf of Mexico are subject to regulation by the BSEE, the BOEM and the Office of Natural Resources Revenue, all of which are agencies of the DOI. The BSEE and the BOEM work to ensure the development of energy and mineral resources on the OCS is done in a safe and environmentally and economically responsible way. The Office of Natural Resources Revenue performs the offshore royalty and revenue management functions of the former Minerals Management Service.

Leasing. The US federal government cannot conduct offshore lease sales without the development and approval of an OCS Program. The OCSLA authorizes the Secretary of the Interior to establish a schedule of lease sales for a five-year period. There is no requirement under the OCSLA that mandates any sales in any locations, nor does the law prescribe any specific timing for the development of the OCS Program. These leases are awarded by the BOEM based on competitive bidding and contain relatively standardized terms. Prior to commencement of offshore operations, lessees must obtain the BOEM's approval for exploration, development and production plans. In addition to permits required from other agencies such as EPA, lessees must obtain a permit from the BSEE prior to the commencement of drilling and comply with regulations governing, among other things, engineering and construction specifications for production facilities, safety procedures, plugging and abandonment of wells on the OCS, calculation of royalty payments and the valuation of production for this purpose, and decommissioning of facilities, structures and pipelines.

In January 2021, President Biden issued an executive order suspending new leasing activities for oil and natural gas exploration and production on federal lands and offshore waters pending review and reconsideration of federal oil and natural gas permitting and leasing practices. After a group of states challenged the executive order, a federal judge required the DOI to stop the leasing pause.

In August 2022, Congress passed the IRA, which required the BOEM to offer at least two million acres for oil and natural gas leasing in the OCS. The IRA also raised the royalty rate for certain offshore leases from 12.5% to 16.67% and capped the rate at 18.75% for ten years.

In November 2021, the DOI released its report on federal oil and natural gas leasing and permitting practices. The report included recommendations in respect to the offshore sector, including adjusting royalty rates to ensure that the full value of leased tracts are captured, strengthening financial assurance coverage amounts that are required by operators, and establishing "fitness to operate" criteria that companies would need to meet in respect of safety, environmental and financial responsibilities in order to operate in the OCS.

In September 2023, consistent with the requirements of the IRA concerning offshore conventional and renewable energy leasing, the DOI announced its proposed 2024 – 2029 OCS Program. The proposed OCS Program includes a maximum of three potential oil and natural gas lease sales in the US Gulf of Mexico scheduled in 2025, 2027 and 2029.

Decommissioning and financial assurance requirements. The BOEM requires that lessees demonstrate financial strength and reliability according to its regulations and provide acceptable financial assurances to assure satisfaction of lease obligations, including decommissioning activities in the OCS. Currently the BOEM requires all lessees of an OCS oil and natural gas lease to post base bonds ranging from US$50,000 to US$3.0 million in addition to supplemental financial assurance determined based on the lessee's ability to carry out present and future financial obligations. See "Environmental regulations – U.S. Bureau of Ocean Energy Management ("BOEM"), the U.S. Bureau of Safety and Environmental Enforcement ("BSEE"), and Office of Natural Resources Revenue ("ONRR") requirements."

Regulation and transportation of natural gas. Our sales of natural gas are affected by the availability, terms and cost of transportation. The price and terms for access to pipeline transportation are subject to extensive regulation. The US Federal Energy Regulatory Commission (the "FERC") has undertaken various initiatives to increase competition within the natural gas industry. As a result of initiatives like FERC Order No. 636, issued in 1992, the interstate natural gas transportation and marketing system allows non-pipeline natural gas sellers, including producers, to effectively compete with interstate pipelines for sales to local distribution companies and large industrial and commercial customers. The most significant provisions of Order No. 636 require that interstate pipelines provide firm and interruptible transportation service on an open access basis that is equal for all natural gas supplies. In many instances, the effect of Order No. 636 and related initiatives have been to substantially reduce or eliminate the interstate pipelines' traditional role as wholesalers of natural gas in favor of providing only storage and transportation services. The rates for such storage and transportation services are subject to the FERC ratemaking authority, and the FERC may apply cost-of-service principles or allow a pipeline to negotiate rates. Similarly, the natural gas pipeline industry is subject to state regulations, which may change from time to time.

The OCSLA, which is administered by the BOEM and the FERC, requires that all pipelines operating on or across the OCS provide open access, non-discriminatory transportation service. One of the FERC's principal goals in carrying out the OCSLA's mandate is to increase transparency in the OCS market, to provide producers and shippers assurance of open access service on pipelines located on the OCS, and to provide non-discriminatory rates and conditions of service on such pipelines. The BOEM issued a final rule, effective August 2008, which implements a hotline, alternative dispute resolution procedures, and complaint procedures for resolving claims of having been denied open and nondiscriminatory access to pipelines in the OCS.

In 2007, the FERC issued rules ("Order 704") requiring that any market participant that engages in wholesale sales or purchases of natural gas that equal or exceed 2.2 million MMBtus during a calendar year must annually report such sales and purchases to the FERC to the extent such transactions utilize, contribute to, or may contribute to the formation of price indices. It is the responsibility of the reporting entity to determine which individual transactions should be reported based on the guidance of Order 704. Order 704 also requires market participants to indicate whether they report prices to any index publishers, and if so, whether their reporting complies with the FERC's policy statement on price reporting. These rules are intended to increase the transparency of the wholesale natural gas markets and to assist the FERC in monitoring such markets and in detecting market manipulation.

Additional proposals and proceedings that might affect the natural gas industry are pending before Congress, the FERC, state legislatures, state commissions and the courts. The natural gas industry historically has been very heavily regulated. As a result, there is no assurance that the less stringent regulatory approach pursued by the FERC, Congress and the states will continue. See "Risk factors – Risks relating to our regulatory, tax and legal environment – Our business is subject to extensive laws and regulations that are subject to change in ways that could adversely affect our business and financial position."

Oil and NGLs transportation rates. Other than as described above, our sales of liquids, which include oil, condensate and NGLs, are not currently regulated and are transacted at market prices. In a number of instances, however, the ability to transport and sell such products is dependent on pipelines whose rates, terms and conditions of service are subject to FERC jurisdiction. The price we receive from the sale of oil and NGLs is affected by the cost of transporting those products to market. Interstate transportation rates for oil, condensate, NGLs and other products are regulated by the FERC. In general, interstate oil, condensate and NGL pipeline rates must be cost-based, although settlement rates agreed to by all shippers are permitted and market-based rates may be permitted in certain circumstances. The FERC has established an indexing system for such transportation, which generally allows such pipelines to take an annual inflation-based rate increase.

In other instances, the ability to transport and sell such products is dependent on pipelines whose rates, terms and conditions of service are subject to regulation by state regulatory bodies under state statutes and regulations. As it relates to intrastate oil, condensate and NGL pipelines, state regulation is generally less rigorous than the federal regulation of interstate pipelines. State agencies have generally not investigated or challenged existing or proposed rates in the absence of shipper complaints or protests, which are infrequent and are usually resolved informally.

Climate Change. The threat of climate change continues to attract considerable public, governmental and scientific attention in the United States. President Biden has made addressing climate change, including the restriction or elimination of greenhouse gas ("GHG") emissions, a priority in his administration.

The IRA includes a methane emissions reduction program that amends the CAA to include a Methane Emissions and Waste Reduction Incentive Program for petroleum and natural gas systems by 2024.

In April 2024, the EPA issued a final rule expanding the scope of the Greenhouse Gas Reporting Program for petroleum and natural gas facilities. Among other things, the rule expands the emissions events that are subject to reporting requirements to include "other large release events," which capture abnormal methane emission events that are not fully accounted for using existing methods, and applies reporting requirements to certain new sources and sectors. The rule will become effective on January 1, 2025, and reporters will implement most of the changes in the 2025 reporting year with reports submitted by March 31, 2026.

In January 2024, the EPA proposed a new rule implementing the IRA's methane emissions charge. The proposed rule includes potential methodologies for calculating the amount by which a facility's reported methane emissions are below or exceed the waste emissions thresholds and contemplates approaches for implementing certain exemptions created by the IRA. The methane emissions charge imposed under the Methane Emissions and Waste Reduction Incentive Program for 2024 would be $900 per ton emitted over annual methane emissions thresholds, and would increase to $1,200 in 2025, and $1,500 in 2026. The implementation of revised air emission standards is likely to increase costs and regulatory burdens on the oil and natural gas industry, especially for smaller operators and operators of older oil and natural gas wells.

The threat of climate change also continues to attract considerable public, governmental and scientific attention in foreign countries. Numerous proposals have been made at the international levels of government to monitor and limit emissions of GHG as well as to restrict or eliminate future emissions. Most recently, at the 28th Conference of the Parties ("COP28"), member countries entered into an agreement that calls for actions toward achieving, at a global scale, a tripling of renewable energy capacity and doubling energy efficiency improvements by 2030. The goals of the agreement include, among other things, accelerating efforts toward the phase-down of unabated coal power, phasing out inefficient fossil fuel subsidies and other measures that drive the transition away from fossil fuels in energy systems. In February 2021, the Biden administration rejoined the Paris Agreement. Pursuant to its obligations as a signatory to the Paris Agreement, the United States has set a target to reduce its GHG emissions by 50% to 52% by the year 2030 as compared with 2005 levels and has agreed to provide periodic updates on its progress. In addition, in November 2021, the United States signed the Global Methane Pledge, a pact that aims to reduce global methane emissions by at least 30% below 2020 levels by 2030. The impacts of these pledges and agreements, and any legislation or regulation promulgated to fulfill the United States' commitments under the COP28 agreement, the Paris Agreement, or the Global Methane Pledge, or other international conventions, cannot be predicted at this time. See "Risk factors – Risks relating to our regulatory, tax and legal environment – Laws regulating greenhouse gas emissions could adversely affect the cost, manner and feasibility of doing business and demand for the oil and gas that we produce."

MANAGEMENT

Board of directors

The following table sets forth certain information regarding our directors.

Name	Age	Position(s)
Dr. Julian Fowles	60	Chief Executive Officer and Managing Director
Peter Botten	69	Independent Non-Executive Chair
Peter Turnbull	65	Independent Non-Executive Director
Clark Davey	67	Independent Non-Executive Director
Luciana Bastos De Freitas Rachid	66	Independent Non-Executive Director
Carlos Tadeu da Costa Fraga	66	Independent Non-Executive Director
Melissa Holzberger	48	Independent Non-Executive Director
Joanne Palmer	49	Independent Non-Executive Director

Dr. Julian Fowles, Chief Executive Officer and Managing Director

Dr Julian Fowles joined our board as chief executive officer and managing director on November 27, 2020.

Dr Fowles started his career with Shell International where he spent 17 years working across the upstream sector in Europe, West Africa, Australasia, South Asia and Latin America, including 5 years as the exploration and new ventures manager in Shell Brazil. Following Shell, he held senior executive positions with Cairn India, Petra Energia, and most recently Oil Search, where he firstly led exploration and new business and then the Papua New Guinea operated and non-operated oil and liquefied natural gas production and development businesses. Leaving Oil Search in late 2018, Dr. Fowles joined the boards of Central Petroleum and FAR Limited in 2019 as an independent non-executive director, roles he relinquished prior to joining us.

Dr Fowles is a graduate of the Australian Institute of Company Directors. He holds a bachelor of science (hons) degree in geology from the University of Edinburgh and a PhD from the University of Cambridge. Dr. Fowles also holds a graduate diploma in applied finance and investment from the Australian Securities Institute.

Peter Botten, Independent Non-Executive Chair

Mr. Botten joined our board on October 1, 2020, and was appointed as the chair of the board on November 23, 2023. He is also a member of the audit and risk committee and a member of the sustainability and operational risk committee. In addition to serving on our board, Mr. Botten currently serves as chair of Aurelia Metals Ltd and chair of Conrad Asia Energy.

Mr. Botten is a former chief executive and business leader with over 40 years of experience in the international resources sector, including as chief executive officer of Oil Search for 26 years. Mr. Botten's executive experience spanned aspects of the upstream petroleum sector including in upstream oil and gas exploration, development and production operations through his involvement in projects in PNG, Australia, Africa, the Middle East and North America. Mr. Botten also has experience in governing and growing ASX-listed companies and other business entities.

Mr Botten holds a bachelor of science degree in geology from the Imperial College of Science and Technology, London University and the Royal School of Mines.

Mr. Peter Turnbull, Independent Non-Executive Director

Mr. Turnbull joined us as independent non-executive director on June 6, 2014. He is also the chairman of our people and culture committee and a member of our audit, risk and governance committee and sustainability and operational risk committee. In addition to serving on our board, Mr. Turnbull currently serves as chair of Calix Limited and chair of Auxita Pty Ltd.

Mr. Turnbull has over 25 years of senior executive and corporate legal experience with Australia's listed and unlisted public companies including Newcrest Mining, BTR Nylex and Energex.

Mr. Turnbull also has corporate, regulatory and government policy experience gained through working with the Australian Securities and Investments Commission and the Hong Kong Securities and Futures Commission. Mr. Turnbull is a former President of the Chartered Governance Institute based in London, a former member of the ASIC Corporate Governance Consultative Panel, a Life Member of the Governance Institute of Australia and a member of the Order of Australia.

Mr. Turnbull holds a bachelor of commerce degree and an LLB degree from the University of Melbourne.

Clark Davey, Independent Non-Executive Director

Mr. Davey joined us as independent non-executive director on October 1, 2010. He is also the chairman of our audit, risk and governance committee and a member of our people and culture committee.

Mr. Davey has over 30 years of experience in the Australian natural resources industry as a taxation consultant to oil and gas and mining companies. Mr. Davey was a partner at Price Waterhouse and PricewaterhouseCoopers specializing in the natural resources industry. For a number of years, he held resource industry leadership roles within both firms. Mr. Davey is a member of the Taxation Institute of Australia and the Australian Institute of Company Directors.

Mr. Davey's prior experience spans company income tax, petroleum resource rent taxation in Australia and assisting with accounting and capital management. He has assisted Australian companies with tax management of their joint venture interests and has had considerable experience with merger and acquisition transactions. He has also assisted companies expand their resource industry interests internationally.

Mr Davey holds a bachelor of commerce degree from the University of Melbourne.

Luciana Bastos De Freitas Rachid, Independent Non-Executive Director

Ms. Bastos De Freitas Rachid joined us as independent non-executive director on August 26, 2016. She is also chair of our sustainability and operational risk committee.

Ms. Bastos De Freitas Rachid has over 35 years of experience in the oil and gas industry in both technical, commercial and senior leadership roles in Brazil, including 20 years in the exploration and production division of Petrobras. She has represented Petrobras as chairperson of Transportadora Brasileira Gasoduto Bolívia-Brasil S.A, and Gás Brasiliano Distribuidora S.A as well as a director of Transportadora Associada de Gás, Companhia de Gás de Minas Gerais and Companhia Paranaense de Gás.

Ms. Bastos De Freitas Rachid has technical experience across project evaluation, development and management roles. Specific experience includes Marlim Leste asset manager, the design of the first offshore platforms in the Campos Basin, the production, handling and processing of natural gas onshore and offshore, the coordination of the Petrobras exploration and production deepwater strategic project and a variety technical and economic feasibility studies on major projects including participation in the first Petrobras project finance deals.

Ms. Bastos De Freitas Rachid has also held positions in the Petrobras commercial team including executive manager of investor relations, executive manager of financial planning and risk management, general manager of corporate affairs, general manager of marketing and trading, executive manager for logistics and investments in natural gas and chief executive officer Transportadora Brasileira Gasoduto Bolivia Brazil and most recently chief executive officer of Transportadora Associada de Gas SA.

Ms. Bastos De Freitas Rachid holds a bachelor of science degree in chemical engineering from Universidade Federal do Rio de Janeiro.

Carlos Tadeu da Costa Fraga, Independent Non-Executive Director

Mr. Fraga joined us as independent non-executive director on August 26, 2022. He is also a member of the sustainability and operational risk committee. Mr. Fraga currently serves as a board member at Vast Infraestrutura (formerly Açu Petróleo), at the Brazilian Institute for Petroleum, Gas and Biofuels and at Radix Engenharia e Software.

Mr. Fraga has 40 years of experience in the oil and gas sector, including 23 years as an executive at Petrobras. Mr. Fraga held various positions at Petrobras over his career, including as Campos Basin production general manager, Gulf of Mexico exploration and production operations manager, board member Petrobras Argentina SA, general manager – domestic oil and gas production, executive manager – exploration and production Brazil – south and southeast regions, executive manager – research and development and exploration and production executive manager – pre-salt developments.

Mr. Fraga is a former chief executive officer of Prumo Logistica and of the Porto do Açu, a former chief technology officer at Gran Energia, as well as a former board member of Gran Bio, GranIHC, Ultrapar, MRO Logistics, Ferroport, Gás Natural do Açu and Porto do Açu (being the chairman at the last three). Mr. Fraga has also served as a board member of several technology institutions in Brazil.

Mr. Fraga holds a bachelor of engineering degree from the Universidade Federal do Rio de Janeiro and is a post-graduate in Petroleum Engineering from Universidade Petrobras. He has also attended executive education programs at University of Alberta (management and regulation in the petroleum industry), Columbia University (executive education in business administration), INSEAD (technology management), London School of Economics (strategic leadership), and Brazilian Institute for Corporate Governance (board member).

Melissa Holzberger, Independent Non-Executive Director

Ms. Holzberger joined us as independent non-executive director on April 19, 2024.

Ms. Holzberger has over 20 years of experience in the international energy and resources sector. She is currently a non-executive director of Argo Investments Ltd, Paladin Energy Ltd, and Intermodal Terminal Company, and a member of the Federal Government's Australian Radiation Protection and Nuclear Safety Agency's Radiation, Health and Safety Advisory Council. Her former directorships include Silex Systems Ltd and Karting Australia.

Ms. Holzberger has also previously worked with BHP Group Ltd (including with its former BHP Petroleum assets) and Rio Tinto plc, and has acted as an adviser to multinational and Australian companies. She has experience in highly regulated industries, legal, risk and compliance oversight and sustainability, environmental, social and governance matters.

Ms. Holzberger holds a master of laws degree in Resources Law from the University of Dundee in Scotland, a bachelor of laws degree and bachelor of arts degree from the University of Adelaide. She is also a Fellow of the Governance Institute of Australia.

Joanne Palmer, Independent Non-Executive Director

Ms. Palmer joined us as independent non-executive director on April 19, 2024.

Ms. Palmer has over 27 years of professional experience providing audit and assurance services, with previous positions at EY and Pitcher Partners. Her international experience spans over 25 years as a former external auditor and advisor to United Kingdom and Australian companies operating in Africa, Europe, America and Australasia.

During her executive career at EY, Ms. Palmer worked primarily in the assurance practice and led EY's financial accounting advisory services team in Perth. Mainly working in the resources sector, she assisted multinational companies, mid-caps and junior explorers by providing external audit services, technical accounting, regulatory advice and finance function support services with a focus on transactions and M&A.

Ms. Palmer currently serves as a non-executive director on the boards of listed companies Paladin Energy, St Barbara, Sierra Rutile Holdings, and unlisted NextOre. She serves as the chair of the audit and risk committees of each of these companies, and is also a member of various additional committees of those boards.

Ms. Palmer holds a bachelor of science degree in Mathematics and Statistics from the University of Birmingham and is a Fellow of the Institute of Chartered Accountants in England and Wales, a Fellow of Chartered Accountants Australia and New Zealand, a former Registered Company Auditor and a Graduate Member of the Australian Institute of Company Directors.

Executive management

The following table sets forth certain information regarding the members of our executive management. See "– Board of directors" for more information in relation to our managing director and chief executive officer, Dr. Julian Fowles.

Name	Age	Position(s)
Dr Julian Fowles	60	Managing Director and Chief Executive Officer
Ray Church	58	Executive Vice President – Chief Financial Officer
Stephen Power	63	Executive Vice President Commercial
Roland Hamp	58	Executive Vice President Technical
Daniel Murnane	45	Executive Vice President – General Counsel and Company Secretary

Dr Julian Fowles is our chief executive officer, a position he has held since 2020. For further information, see "– Board of directors."

Ray Church, Executive Vice President – Chief Financial Officer

Mr. Church has served as our executive vice president – chief financial officer since 2021. Mr Church has more than 36 years of international experience in finance roles. He has worked in multiple jurisdictions, including the United States, Papua New Guinea, Kazakhstan, Russia and China, as well as Europe and Australia.

Mr. Church has more than two decades of oil and gas experience, having previously held the position of vice president, finance at TNK-BP and a variety of senior finance and commercial roles at Chevron Corporation. Mr. Church was also the chief financial officer at UGL Limited. He holds a bachelor of commerce degree from James Cook University and is a chartered accountant.

Stephen Power, Executive Vice President Commercial

Mr. Power has served as our executive vice president commercial since 2021.

Mr. Power is a commercial lawyer with more than 35 years of experience advising clients in the energy and resources industry in Australia and overseas, including South America, North America, West Africa and the UK.

Mr. Power is qualified as a Corporate Legal Practitioner in Victoria, Australia and holds a Bachelor of Jurisprudence and a bachelor of Laws degree from the University of Western Australia.

Roland Hamp, Executive Vice President Technical

Mr. Hamp has served as our executive vice president technical since 2023.

Mr. Hamp has more than 35 years of experience in the oil and gas sector, holding various technical and management positions in the UK and Australia, primarily with Enterprise Oil plc and Woodside Energy Limited. Most recently he was a technical and operations advisor to the department of industry, science and resources, the Commonwealth Government of Australia, on a range of offshore matters. He is a fellow of the Institution of Engineers Australia and has been a member of the Society of Petroleum Engineers since 1983.

Mr. Hamp holds a master of engineering degree from Imperial College, London (with first class honors). He has also attended executive training programs at Thunderbird International Business School, the University of Western Australia and the Australian Institute of Company Directors.

Daniel Murnane, Executive Vice President – General Counsel and Company Secretary

Mr. Murnane has served as our executive vice president – general counsel and company secretary since 2022.

Mr. Murnane has more than 16 years of experience gained in Australia and internationally, including over 12 years advising resources companies. He has worked as a senior associate in private legal practice predominately for energy companies on mergers and acquisitions, major projects, capital raisings and commercial disputes.

In addition, Mr. Murnane has held various in-house roles spanning legal and corporate governance environments, including with ASX and NYSE listed oil and gas companies.

Mr. Murnane is qualified as a solicitor in New South Wales and Papua New Guinea and holds a bachelor of arts degree and a bachelor of laws degree from the University of Canberra.

Board practices

Role and responsibilities

Our governing body is the board of directors. The board acts on behalf of shareholders and is accountable to shareholders for our overall direction and governance.

The role and responsibility of the board is to oversee and direct our senior management by:

- defining and monitoring our strategic direction;
- defining policies and procedures to ensure we operate within the legal, ethical and social requirements of our environment;
- establishing control and accountability systems within our operations to conform to the legal requirements and the expectations of shareholders and other stakeholders;
- defining and monitoring the management of an effective risk assessment strategy;
- securing funds to develop our assets;
- driving our performance.

Responsibility for our day-to-day management and administration is delegated by the board to the chief executive officer and managing director appointed by the board and other senior executives approved by the board. The delegation of authority is formally documented in our delegation of authority. Management is accountable to the board for the discharge of this delegated authority and for compliance with any limits on that authority.

The board met seventeen times during FY23 and nine times during TY23.

Board access to information and independent advice

All directors have the right to access company information. Our directors may seek independent professional advice at our expense where the director reasonably considers, after consulting with the chair, that obtaining independent advice is appropriate, and where the chair consents to the obtaining of that advice (with this consent not being unreasonably withheld).

Conflicts of interests

Directors must declare any conflict of interest that they may have at the start of all board meetings. Where a material personal interest arises with respect to a matter that is to be considered by the board, the director is required to declare that interest and must not take part in any board discussion or vote in relation to that matter, unless permitted in accordance with the Australian Corporations Act.

Independence

The board assesses the independence of each director, having regard to the ASX Corporate Governance Council's Principles and Recommendations 4th Edition, in light of information disclosed by each director to the board. Accordingly, when determining the independence of a non-executive director, the board considers whether the director:

- is, or has been, employed in an executive capacity by us or any of our subsidiaries and there has not been a period of at least three years between ceasing such employment and serving on the board;

- receives performance-based remuneration (including options or performance rights) from, or participates in an employee share incentive scheme;

- is, or has been within the last three years, in a material business relationship (e.g. as a supplier, professional adviser, consultant or customer) with us or any of our subsidiaries, or an officer of, or otherwise associated with, someone with such a relationship;

- is, represents, or has been within the last three years an officer or employee of, or professional adviser to, a substantial holder;

- has close personal ties with any person who falls within any of the categories described above; or

- has been a director of the entity for such a period that their independence from management and substantial holders may have been compromised.

In each case, the materiality of the interest, position, association or relationship is assessed by the board to determine whether it might interfere, or might reasonably be seen to interfere, with the director's capacity to bring an independent judgement to bear on issues before the board and to act in our best interests as a whole rather than in the interests of an individual security holder or other party.

Board committees, membership and charters

The board has the ability under our constitution to delegate its process and responsibilities to committees of the board. As of December 31, 2023 the board has established three standing committees to assist it in effectively exercising its responsibilities.

These are the:

- audit, risk and governance committee;
- people and culture committee; and
- sustainability and operational risk committee.

The board reviews the performance of the committees and considers whether new committees are required. During FY23, the board undertook a comprehensive review of the performance and charters of the board and its committees.

Audit, risk and governance committee

The role of the audit, risk and governance committee is to oversee the financial reporting process to seek to ensure the balance, transparency and integrity of published financial information, oversee risk identification and management and ensuring that we have the appropriate ethical standards and corporate governance policies and practices in place. The board has formally adopted an audit, risk and governance committee charter.

The responsibilities of the audit, risk and governance committee include:

Powers and functions

- improving the credibility and objectivity of our accountability processes (including financial reporting);
- engaging independent counsel and other advisers it seems necessary to carry out its duties;
- regularly assessing the need for an internal audit function and implement as required;
- ensuring the attendance of our officers at meetings as appropriate;
- being directly responsible for recommending to the board the appointment, compensation, retention and oversight of the work of the external auditor, including rotation of the external audit engagement partner; and
- recommending to the board all external audits and review engagement fees and terms as well as reviewing policies for the provision of non-audit services by the external auditor (and, when required, the framework for the pre-approval of such services).

Financial risk management and internal control

- leading our strategic direction in the management of material business risks (but excluding operational risks);
- working with the board and management to determine our risk tolerance;
- evaluating whether management is setting the appropriate control culture by communicating the importance of internal control and management of business risk;
- understanding the internal control systems implemented by management for the approval of transactions and the recording and processing of financial data; and
- understanding the controls and processes implemented by management to ensure that the financial statements derived from the underlying financial systems, comply with relevant Australian Accounting Standards and requirements, and are subject to appropriate management review.

Financial reporting

- gaining an understanding of the current areas of greatest financial risk and how these are being managed;
- reviewing significant accounting and reporting issues, including recent professional and regulatory pronouncements, and understanding their impact on financial reports;
- meeting with management and the external auditor to review financial statements, key accounting policies, judgements and decisions, and the results of the audit;
- providing a recommendation to the board as to whether our financial statements reflect the understanding of the committee members, and otherwise provide a true and fair view, of the financial position and our performance;
- obtaining from the chief executive officer and the chief financial officer, a written declaration under s 295A of the Corporations Act that:
    - o financial records have been properly maintained in accordance with the Corporations Act;
    - o written declarations have been received from senior management within each of our jurisdiction confirming tax compliance of financial statements within that jurisdiction;
    - o financial statements present a true and fair view, in all material respects, of our financial condition, operational results and are in accordance with relevant accounting standards; and
    - o there is an effective and efficient operation of our financial risk management and internal compliance and control system;
- reviewing the directors' report;
- reviewing the annual report; and
- reviewing the annual financial budget, including providing feedback on assumptions, objectives and fulfilling our strategic objectives.

Working with the external auditor

- reviewing the professional qualification of the external auditor (including background and experience of partner and auditing personnel);
- considering the independence of the external auditor and any potential conflicts of interest;
- reviewing on an annual basis the performance of the external auditor and making recommendations to the board for the appointment, reappointment or termination of the appointment of the external auditor;
- reviewing the external auditor's proposed audit scope and approach for the current year in light of our circumstances and changes in regulatory and other requirements;
- discussing with the external auditor any audit problems encountered in the normal course of audit work, including any restrictions on audit scope or access to information;
- ensuring that significant findings and recommendations made by the external auditor and management's proposed response are received, discussed and acted on appropriately;
- discussing with the external auditor the appropriateness of the accounting policies applied in our financial reports and whether they are considered to be aggressive, balanced or conservative; and
- reviewing policies for the provision of non-audit services by the external auditor and, where applicable, the framework for pre-approval of audit and non-audit services.

The audit, risk and governance committee reports to the board after each committee meeting and minutes of meetings are provided to all directors.

As of December 31, 2023, the audit, risk and governance committee consisted of the following three independent non-executive directors:

- Mr. Clark Davey (Chair of Committee);
- Mr. Peter Turnbull; and
- Mr. Peter Botten.

The audit, risk and governance committee met six times during FY23 and two times during TY23.

People and culture committee

The role of the people and culture committee is to oversee the following:

People and culture

- overseeing the development and implementation of employee performance and development programs and succession plans to attract, motivate and retain high quality people to enable appropriate skills, experience and the capability to deliver on our business strategy;
- overseeing our approach to culture and diversity;
- reviewing and monitoring employee engagement;
- reviewing on at least an annual basis, the measurable objectives for achieving gender diversity under the Diversity Policy and in accordance with the ASX Corporate Governance Council's Principles and Recommendations and assessing progress against the objectives; and
- monitoring the effective communication of the diversity policy and performance review policy.

Remuneration strategy, policies and structure

With respect to employees (excluding the chief executive officer and managing director in respect of whom such matters are reserved for the board), reviewing, monitoring and making recommendations to the board on the following:

- defining our remuneration policies and strategic objectives for remuneration frameworks to ensure they are informed by market practice, trends and legislative and regulatory requirements;
- assessing the separate policies and practices regarding remuneration of senior executives;
- our recruitment, retention and termination policies and procedures for senior executives;
- seeking external advice to ensure that employees are being rewarded with remuneration packages commensurate with their responsibilities and making recommendations to the board on any incentive scheme and any proposed changes;
- reporting on the progress against the long-term performance hurdles making recommendations on equity allocations, including outcomes of short-term objectives in line with company performance;
- recommendations from the chief executive officer and managing director relating to proposed merit increases for direct reports;
- overseeing fee frameworks, including superannuation arrangements for senior executives and other employees;
- identifying any changes to the senior executive remuneration policy;
- reviewing and recommending to the audit, risk and governance committee and the board the annual audited remuneration report for approval; and
- considering the outcome of the annual shareholder advisory vote on the adoption of the remuneration report and feedback of key stakeholders.

The people and culture committee reports to the board after each committee meeting and minutes of meetings are provided to all directors.

As of December 31, 2023, the people and culture committee consisted of the following three independent directors:

- Mr. Peter Turnbull (Chair of Committee);
- Mr. Peter Botten; and
- Mr. Clark Davey.

The people and culture committee met five times during FY23 and two times during TY23. For further information on management remuneration, please refer to the remuneration reports for TY23, FY23 and FY22, included elsewhere in this offering memorandum.

Sustainability and Operational Risk Committee

The sustainability and operational risk committee is responsible for:

Strategic direction

- leading our strategic direction in the management of material operational risks;
- working with the board and management to determine our operational risk tolerance;
- identifying opportunities to minimize the potential for harmful environmental or social impacts arising from our operations; and
- key policies and strategies in relation to the health and safety of our employees and the environmental and social impacts of our operations, including the:
  - o HSSE policy;
  - o risk management policy; and
  - o sustainability policy.

Oversight

- operational risk profile and risk management framework;
- implementation and review of operational risk management and internal compliance and control systems;
- management and identification of material exposure to operational, environmental and social sustainability risks and how those risks are managed;
- our OMS with a focus on HSSE issues; and
- our environmental and social programs.

Review

- on at least an annual basis, the effectiveness of our operational risk management framework in identifying and managing operational risks and controlling internal processes;
- management's plans for mitigation of material operational risks faced by us;
- the operational risk register on a periodic basis, identifying the main internal and external risk sources including material exposures to operational, environmental and social sustainability risks associated with our equity/participatory interests in oil and gas exploration, development and production projects and operations;
- our operational insurance program;
- our HSSE performance;
- any environmental or social impacts arising from our operations;

- compliance with our OMS and legislative and regulatory requirements with respect to HSSE and sustainability issues, including the requirements of approved environmental plans related to our operations; and

- our annual sustainability report, which includes our carbon emissions reporting, having regard to the recommendations of the financial stability board's taskforce on climate related financial disclosures.

Recommendations

- our operational risk tolerance and particular operational risks and/or risk management practices;

- continuous improvement of operational risk management and internal control processes, including any issues arising from reviews;

- our environmental and social programs; and

- external best practice developments and trends in relation to sustainability and operational, risk management policy and practice.

The sustainability and operational risk committee reports to the board after each committee meeting and minutes of meetings are provided to all directors.

As of December 31, 2023, the sustainability and operational risk committee consisted of the following four independent directors:

- Ms. Luciana Rachid (chair of committee);

- Mr. Peter Turnbull;

- Mr. Peter Botten; and

- Mr. Carlos Tadeu da Costa Fraga.

The sustainability and operational risk committee met four times during FY23 and two times during TY23.

Corporate governance

As a company listed on the ASX, we are required to comply with the Australian Corporations Act, the ASX Listing Rules and other Australian and international laws. The ASX Listing Rules require us to report on the extent to which we have followed the Corporate Governance Recommendations published by the ASX Corporate Governance Council in the fourth edition of the Corporate Governance Principles and Recommendations. We believe that throughout the FY23, TY23, and at the date of our last annual report (February 29, 2024), we have complied with all of these recommendations.

Compensation

For information on the compensation and share ownership of our directors and key management personnel in TY23, FY23 and FY22, please see the remuneration reports and Note 27 to our TY23 consolidated financial statements included elsewhere in this offering memorandum. We follow the principles of remuneration that are set out in the ASX Corporate Governance Council's Corporate Governance Principles and Recommendations. These include a policy of rewarding employees with a mixture of fixed, performance-linked and equity-based remuneration.

PRINCIPAL SHAREHOLDERS AND RELATED PARTY TRANSACTIONS

Principal Shareholders

We are a public company listed on the ASX.

As of February 13, 2024, our largest shareholders are HSBC Custody Nominees (Australia) Limited, holding 29.06%, JP Morgan Nominees Australia Pty Limited, holding 19.39%, Citicorp Nominees Pty Limited, holding 14.26% and National Nominees Limited, holding 4.67% of our issued ordinary shares respectively.

We are not aware of any arrangements the operation of which may at a subsequent date result in a change of control of Karoon Energy.

Related Party Transactions

We enter into transactions with certain related parties or our affiliates from time to time and in the ordinary course of our business. We believe these agreements are on terms no more favorable to the related parties or our affiliates than they would expect to negotiate with disinterested third parties, unless otherwise stated.

From time to time, we provide accounting, administrative and technical services to subsidiaries at cost or at cost plus a mark-up where required under relevant tax transfer pricing legislation. We also provide funding to our overseas subsidiaries via an increase in contributed equity and intercompany loans to Australian subsidiaries. Intercompany loans are provided at a nil % interest rate and no fixed term for repayment. These transactions are eliminated when we consolidate our financial statements.

For a discussion of related party transactions, see Note 27 to our consolidated financial statements for TY23, included elsewhere in this offering memorandum.

DESCRIPTION OF OTHER FINANCING ARRANGEMENTS

Below is a summary of our other material borrowings that will remain outstanding as of the date of this offering memorandum. This summary does not purport to be complete and is subject to, and qualified in its entirety by reference to, the underlying documents.

Reserve Based Lending Facility

Overview

On November 16, 2023, we entered into a senior secured syndicated facility agreement with, among others, Deutsche Bank AG, Sydney Branch, ING Belgium SA/NV, Macquarie Bank Limited and Shell Western Supply and Trading Limited, as original lenders, Global Loan Agency Services Australia Pty Ltd as agent and Citibank, N.A., London Branch, as offshore security agent.

The syndicated facility provides for a U.S. dollar-denominated revolving credit facility with commitments totaling US$340 million, which will be reduced in accordance with the reduction schedule described below (the "Initial Facility"). We expect that when our interest in the Who Dat assets is added to the borrowing base, the full US$340 million committed under the RBL facility will become available, subject to customary conditions to draw. Subject to satisfying certain conditions, we have the option of increasing the commitments under the syndicated facility by up to US$200 million through the establishment of accordion facilities (each an "Accordion Facility" and, together with the Initial Facility, the "RBL facility").

Borrowing Base Limit

The maximum amount that may be drawn and outstanding under the RBL facility is equal to the lesser of the total commitments and a borrowing base limit, which is redetermined as at each March 31 and September 30, commencing March 31, 2024. The borrowing base limit is the lesser of (a) the sum of capital expenditure addback value and the net present value of the forecast cashflow available for debt service of the borrowing base assets over their field life divided by 1.5 and (b) the sum of capital expenditure addback value and the net present value of the forecast cashflow available for debt service of the borrowing base assets over the RBL facility life divided by 1.3. The capex addback value is the lower of (i) the present value of the forecast capital expenditure in respect of the borrowing base assets for the 12-month period from the relevant redetermination date and (ii) the sum of each available facility, cash and cash equivalent investment and other permitted available funding sources that are committed and reasonably anticipated to be available to fund such capital expenditure. There may also be interim redeterminations of the borrowing base limit in certain circumstances. Loan drawdowns are also subject to customary conditions precedent.

The initial borrowing base assets consisted of our net working interest in the Baúna and Patola fields (BM-S-40) and Neon field (S-M-1037 and S-M-1102). The RBL facility provides for additional assets to be designated as borrowing base assets upon satisfaction of various conditions (including majority lender approval), and we are required to request that the Who Dat Assets are included as borrowing base assets as soon as reasonably practicable following their acquisition. We are currently in the process of incorporating our interest in the Who Dat oil and gas fields into our borrowing base assets, and we expect this process to complete by June 30, 2024, although there can be no assurance as to whether the RBL facility lenders will accept the Who Dat assets as a borrowing base asset or the timing for such designation. In certain circumstances, we may also de-designate petroleum assets such that they cease to be borrowing base assets.

We may use amounts borrowed under the Initial Facility for general corporate purposes (other than for the purpose of paying a dividend). An Accordion Facility may be used for the purposes agreed with the applicable Accordion Facility lenders.

Borrowers and guarantors

KEI (Brazil Santos) Pty Ltd, Karoon Petróleo e Gás Ltda ("KPG") and KEI Finance 1 Pty Ltd are the original borrowers under the RBL facility and they also guarantee each other borrower's obligations (the "Original Borrowing Base Obligors" and, together with any other person which becomes a borrower under the RBL facility or which is or becomes a guarantor under the RBL facility and directly owns our interest in a Borrowing Base Asset, the "Borrowing Base Obligors"). The borrowers' obligations under the RBL facility are also guaranteed by the Parent Guarantor and Karoon Energy International Pty Ltd (the "Original Corporate Guarantors" and, together with any other person which becomes a guarantor under the RBL facility, the "Corporate Guarantors", and the Corporate Guarantors and the Borrowing Base Obligors, collectively, the "Obligors"). The Issuer, KUSA Inc. and A.C.N. 672 679 793 Pty. Ltd. will become Corporate Guarantors on or before the issuance of the Notes. The guarantors under the RBL facility (including the Borrowing Base Obligors) will also be guarantors of the Notes. Subject to certain conditions, we may add or retire borrowers and guarantors under the RBL facility. Such additional borrowers shall become Borrowing Base Obligors and such additional guarantors shall become Borrowing Base Obligors if they directly own the Group's interest in a borrowing base asset. For the avoidance of doubt, a Corporate Guarantor will become a Borrowing Base Obligor (and cease to be a Corporate Guarantor) if it subsequently becomes a borrower under the RBL facility or the direct owner of the Group's interest in the borrowing base assets. Subject to certain exceptions and agreed security principles, we are required to ensure that the obligors account for at least 90% of EBITDAX of the Group and 90% of total assets of the Group on each June 30 and December 31 (each a "Reporting Date"), commencing on June 30, 2024. The RBL facility contains agreed security principles that govern the terms on which security and guarantees are provided (including the scope of the collateral) to facilitate the negotiation of future individual security documents and the joinder of future borrowers and guarantors (the "security principles").

Term

The Initial Facility matures on the earlier of (i) September 30, 2028 and (ii) the date by which the aggregate remaining 2P reserves of the borrowing base assets will be equal to or less than 25% of the borrowing base asset 2P reserves as of the closing of the Initial Facility. The maturity of an Accordion Facility will be the date agreed with the applicable Accordion Facility lenders provided that it may not be earlier than the maturity of the Initial Facility.

Reduction and Repayment

The total committed facility amount under the Initial Facility reduces in accordance with the following amortization schedule:

	Total committed facility amount
Initial Facility closing date	US$340,000,000
March 31, 2026	US$283,333,333
September 30, 2026	US$226,666,667
March 31, 2027	US$170,000,000
September 30, 2027	US$113,333,333
March 31, 2028	US$56,666,667
September 30, 2028	US$nil

The amortization schedule for an Accordion Facility (if any) will be as agreed with the relevant Accordion Facility lenders, provided that the weighted average life may not be shorter than that applicable to the Initial Facility.

Voluntary Prepayment and Cancellation

Subject to minimum quantitative thresholds and payment of break costs (if any), we may, at any time (by giving three business days' notice) cancel and/or prepay the whole or any part of the available aggregate facility at that time. Subject to certain conditions and exceptions, any amounts prepaid or repaid may be reborrowed while any amounts that are canceled may not be reinstated.

Mandatory Prepayment and Review Events

Change of operator

We may be required to prepay the lenders if KPG ceases to be the operator of the Baúna and Patola fields (BM-S-40) or if we cease to own at least 50% of the aggregate net working interests in the Baúna and Patola fields (BM-S-40).

Disposal and insurance proceeds

Subject to certain customary exclusions, thresholds and reinvestment rights, we are required to prepay loans and cancel available commitments using the net cash proceeds from any permitted disposals of borrowing base assets or insurance claims relating to the borrowing base assets to the extent required to ensure that the outstanding RBL facility amount does not exceed the then-applicable borrowing base limit (determined after taking into account the relevant disposal or insurance event).

Borrowing Base Deficiency

We will also be required to prepay any amounts borrowed under the RBL facility that exceed the borrowing base limit on any borrowing base redetermination date. Such repayments must be made within 60 days of the relevant borrowing base redetermination date (or, if later, 60 days after the adoption of the relevant banking case showing that a borrowing base deficiency exists).

Review events

Review events under the RBL facility include a change of control, the delisting of the Parent Guarantor from the ASX, a suspension of the Parent Guarantor's shares from trading on the ASX for a continuous period of 10 business days (other than for certain imminent transaction announcements) or the unanticipated cessation of production for at least 90 continuous days, termination or cancellation of certain material contracts or governmental authorization or governmental intervention in the borrowing base assets. Following the occurrence of a review event, we may agree with the lenders to amend the RBL facility. If we and the lenders cannot agree to a basis on which the facility will continue, we may be required to pay all or a part of the amounts outstanding under the RBL facility.

Interest and Fees

The interest rate on loans under the RBL facility is calculated by reference to a margin over SOFR plus a credit adjustment spread. The margin applicable to Initial Facility loans is 4.00% per annum.

We must pay a commitment fee with respect to the Initial Facility equal to 40% of the margin on the undrawn Initial Facility commitment (other than the portion (if any) exceeding the borrowing base limit); and 20% of the margin on the portion (if any) of the undrawn Initial Facility commitment exceeding the borrowing base limit.

We are required to pay letter of credit fees and any applicable issuance fees and costs as agreed with the applicable issuing bank in relation to any letters of credit issued under the RBL facility.

The margin, any commitment fees and any establishment or similar fees applicable to an Accordion Facility will be as agreed with the relevant lenders.

Guarantee and Security

The RBL facility is secured on a senior secured basis by the following assets and security, subject to customary exceptions and the security principles:

(a) the shares or other equity ownership interests in the Borrowing Base Obligors, the material borrowing base assets of the Borrowing Base Obligors (including bank accounts, material contracts, insurance policies, hedging policies and intra-group loans) and an all-assets general security deed or equivalent composite security over the assets of the Borrowing Base Obligors incorporated in Australia; and

(b) the shares or other equity ownership interests in the Corporate Guarantors (other than the Parent Guarantor) and, an all-assets general security deed or equivalent composite security over the assets of the Corporate Guarantors.

The security documents are governed by Australian, Brazilian or English law, as applicable. Further U.S. law security will be entered into as part of the designation of the Issuer and KUSA Inc. as Corporate Guarantors and the subsequent designation of KUSA Inc. as a Borrowing Base Obligor upon the designation of the Who Dat asset as borrowing base assets under the RBL facility.

The RBL facility includes customary further assurance obligations, subject to the security principles, for the creation of additional security by existing and future Borrowing Base Obligors and Corporate Guarantors.

The Notes will be secured on a second lien basis (subject to the security principles and applicable local law) over the same assets as the RBL facility.

Covenants and Undertakings

Financial Covenants – Borrowing Base Obligors

The RBL facility contains the following financial covenants in relation to the Borrowing Base Obligors:

(a) Debt service cover ratio (being the trailing twelve month ratio of cashflow available for debt service to debt service) of not less than 1.10 times as of each Reporting Date and 1.20 times as of any three consecutive Reporting Dates.

(b) Forecast 12-month liquidity ratio (being the 12-month forecast ratio of total funding sources to total funding uses) of at least 1.10 times as of each borrowing base limit redetermination date.

(c) Minimum cash balance of US$20,000,000 (or its equivalent in other currencies) as of the last business day of each calendar month.

We are permitted to cure a failure to comply with the above financial covenants by repaying debt (in the case of the debt service cover ratio) which will be counted as cashflow available for debt service or contributing cash and cash equivalents to the Borrowing Base Obligors (in the case of the liquidity ratio or minimum cash balance).

Financial Covenant – Group

We are required to ensure that the leverage ratio (the ratio of net debt of the Group to EBITDAX of the Group) is not greater than 3.25 times as of each Reporting Date. Net debt is calculated as debt less cash and cash equivalents as shown on our financial statements.

We are permitted to cure a failure to comply with the leverage ratio by procuring an equity contribution which will be counted as EBITDAX.

The following table sets out the relevant financial ratios as calculated using the financial covenant calculations documented in the syndicated facility agreement as of December 31, 2023.

	Covenant level	Level as of December 31, 2023
Financial covenants		
Debt service cover ratio	No less than 1.1x	9.8x
Liquidity ratio	At least 1.1x	1.41x
Minimum cash balance	Greater than US$20.0 million	US$139.6 million
Net leverage ratio	Not greater than 3.25x	0.2x

General Covenants – Obligors

The RBL facility includes certain customary undertakings imposing obligations and restricting operations and the ability for any Obligor to take certain actions, subject to certain agreed exceptions and qualifications. The RBL facility also includes restrictions on the Obligors, subject to certain agreed exceptions and qualifications, including but not limited to (i) creating security interests; (ii) conduct of business; (iii) disposing of assets or entering into merger transactions; (iv) incurring additional debt; (v) granting guarantees and indemnities; and (vi) issuance of further shares.

General Covenants – Borrowing Base Obligors

In addition to the above, the RBL facility includes certain undertakings imposing obligations and restricting operations and the ability for any Borrowing Base Obligor to take certain actions, including but not limited to: (i) hedging arrangements; (ii) incurrence of debt and issue guarantees; (iii) maintenance of borrowing base assets (including performance under field documents); (iv) entering into, amending or terminating field documents; (v) acquisitions; (vi) distributions (including requiring the approval of the majority of the lenders under the RBL facility if the proportion of the borrowing base limit under the RBL facility attributable to development assets exceeds 35% of the total borrowing base limit); (vii) entering into joint venture arrangements; (viii) compliance with environmental laws; (ix) ensuring not less than 75% of net entitlements to production from the borrowing base assets are subject to acceptable offtake arrangements; and (x) amendments to other debt documents.

Hedging

Under our RBL facility, we are required to enter into hedging arrangements to mitigate our exposure to movements in oil prices by reference to a minimum proportion of our forecast production from Baúna on a rolling two-year basis. If we establish an Accordion Facility, our hedging obligation will be calculated by reference to a minimum proportion of our forecast production from the borrowing base assets instead. Our hedging requirements are re-assessed 60 days after the date of each loan and Accordion Facility loan and every six months thereafter. The amount we are required to hedge is determined by our collateral coverage ratio at each testing date, which is calculated by reference to the value of Baúna or our borrowing base assets, as applicable, and the amount we have drawn down under the facility. We are prohibited from hedging more than 70% of our forecast production under our RBL facility. The table below sets forth our minimum hedging requirements over the following 6, 12, 18 and 24 months as determined by reference to our collateral coverage ratio as of each testing date.

	Forecast production over the next			
	6 months	12 months	18 months	24 months
Collateral coverage ratio as of each testing date				
Less than or equal to 1.25x	40.0%	30.0%	23.0%	17.0%
Greater than 1.25x and less than or equal to 1.67x....................................	30.0%	23.0%	17.0%	–
Greater than 1.67x and less than or equal to 2.5x......................................	23.0%	17.0%	–	–
Greater than 2.5x and less than or equal to 5.0x......................................	17.0%	–	–	–
Greater than 5.0x................................	–	–	–	–

Events of Default

The RBL facility includes customary events of default for facilities of its type, which are subject to customary grace periods, thresholds and other qualifications.

The occurrence of an event of default under the RBL facility would allow the lenders (if a two-thirds majority of lenders so direct) to cancel their commitments and/or declare that all or part of the loans, together with accrued interest and other amounts outstanding:

- are immediately due and payable;
- payable immediately on demand;
- declare that full cash cover in respect of each letter of credit is immediately due and payable;
- declare that cash cover in respect of each letter of credit is payable on demand; and/or
- direct the security agent to exercise any rights available under the finance documents.

Governing Law and Jurisdiction

The RBL facility is governed by English law.

INDEPENDENT AUDITORS

The consolidated financial statements of Karoon Energy Limited as of and for the transitional financial year ended December 31, 2023 and as of and for the financial years ended June 30, 2023 and 2022, included in this offering memorandum, have been audited by PricewaterhouseCoopers, independent auditors, as stated in their reports dated February 29, 2024, August 23, 2023 and August 25, 2022, respectively, appearing herein.

With respect to the unaudited condensed consolidated financial statements of Karoon Energy Limited as of and for the half-year ended December 31, 2022, included in this offering memorandum, PricewaterhouseCoopers reported that they have applied limited procedures in accordance with professional standards for a review of such information. However, their separate report dated February 22, 2023 appearing herein states that they did not audit and they do not express an opinion on the unaudited condensed consolidated financial statements. Accordingly, the degree of reliance of their report on such information should be restricted in light of the limited nature of the review procedures applied.

The liability of PricewaterhouseCoopers, in relation to the performance of their professional services provided to Karoon Energy Limited including, without limitation, PricewaterhouseCoopers's audits and reviews of Karoon Energy Limited's financial statements described above, is limited under the Chartered Accountants Australia and New Zealand Scheme (NSW) (the "Accountants Scheme") approved by the New South Wales Professional Standards Council or such other applicable scheme approved pursuant to the Professional Standards Act 1994 (NSW) (the "Professional Standards Act"). Specifically, the Accountants Scheme limits the liability of PricewaterhouseCoopers to a maximum amount of A$75 million for audit work and A$20 million for other work. The Accountants Scheme does not limit liability for breach of trust, fraud or dishonesty. These limitations of liability may limit enforcement in Australian court of any judgment under United States or other foreign laws rendered against PricewaterhouseCoopers based on, or related to, its audit of the financial statements of Karoon Energy Limited. The Accountants Scheme commenced on October 8, 2019 and will remain in force for a period of five years (unless it is revoked, extended or ceases in accordance with the Professional Standards Act). The Professional Standards Act and the Accountants Scheme have not been subject to relevant judicial consideration and, therefore, how the limitations will be applied by courts and the effect of the limitations on the enforcement of foreign judgments is untested.

PricewaterhouseCoopers' registered address is 2 Riverside Quay, Southbank VIC 3006, Australia.

The audited statements of revenues and direct operating expenses of the Who Dat assets for each of the two years in the period ended December 31, 2023 and included in this offering memorandum have been audited by Ernst & Young LLP, independent auditors, as stated in their report appearing herein.

Ernst & Young LLP's registered address is 3900 Hancock Whitney Center, 701 Poydras Street, New Orleans, Louisiana 70139.